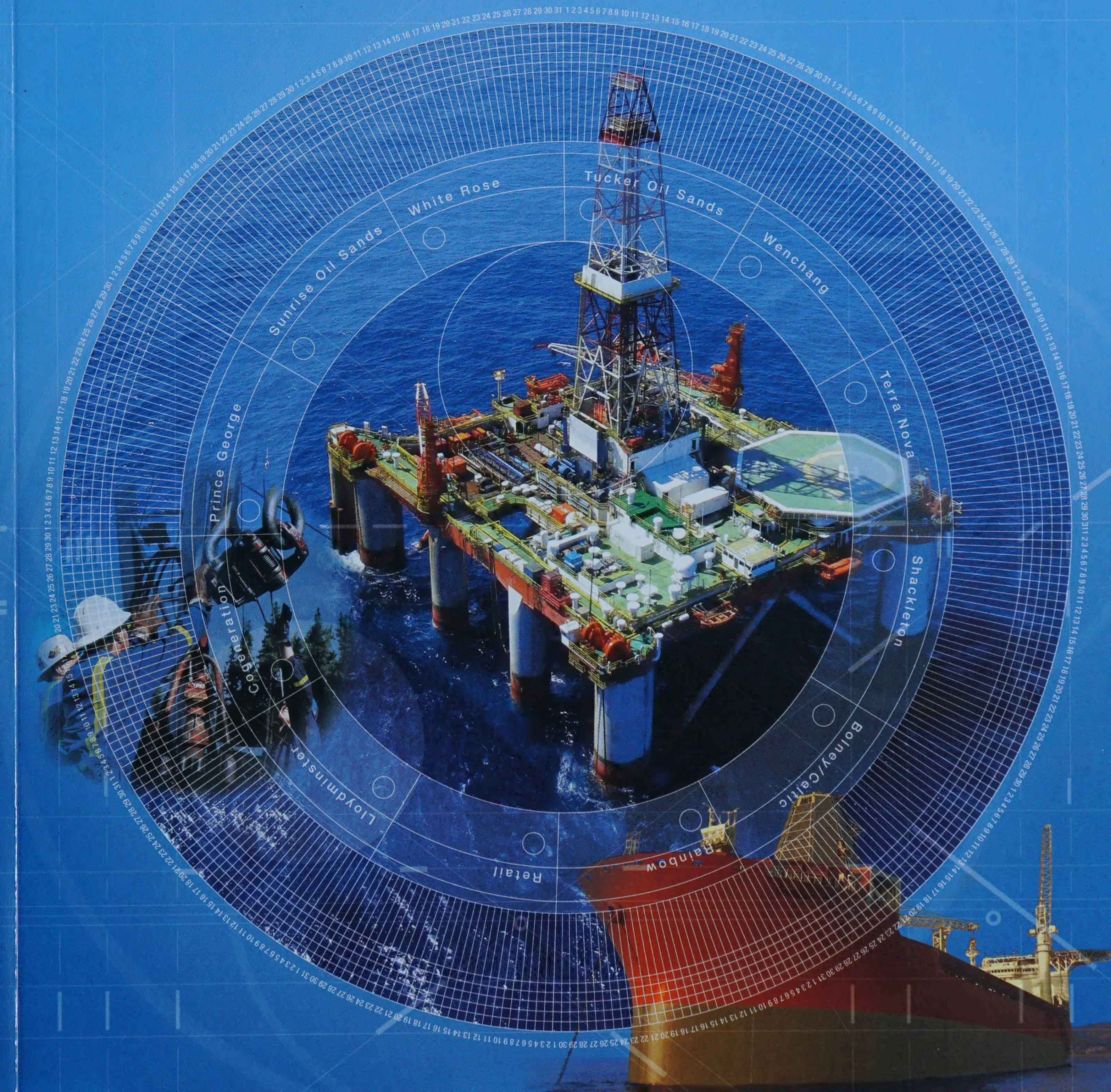
HUSKY ENERGY INC.

ANNUAL REPORT

BUILDING ON THE HORIZON

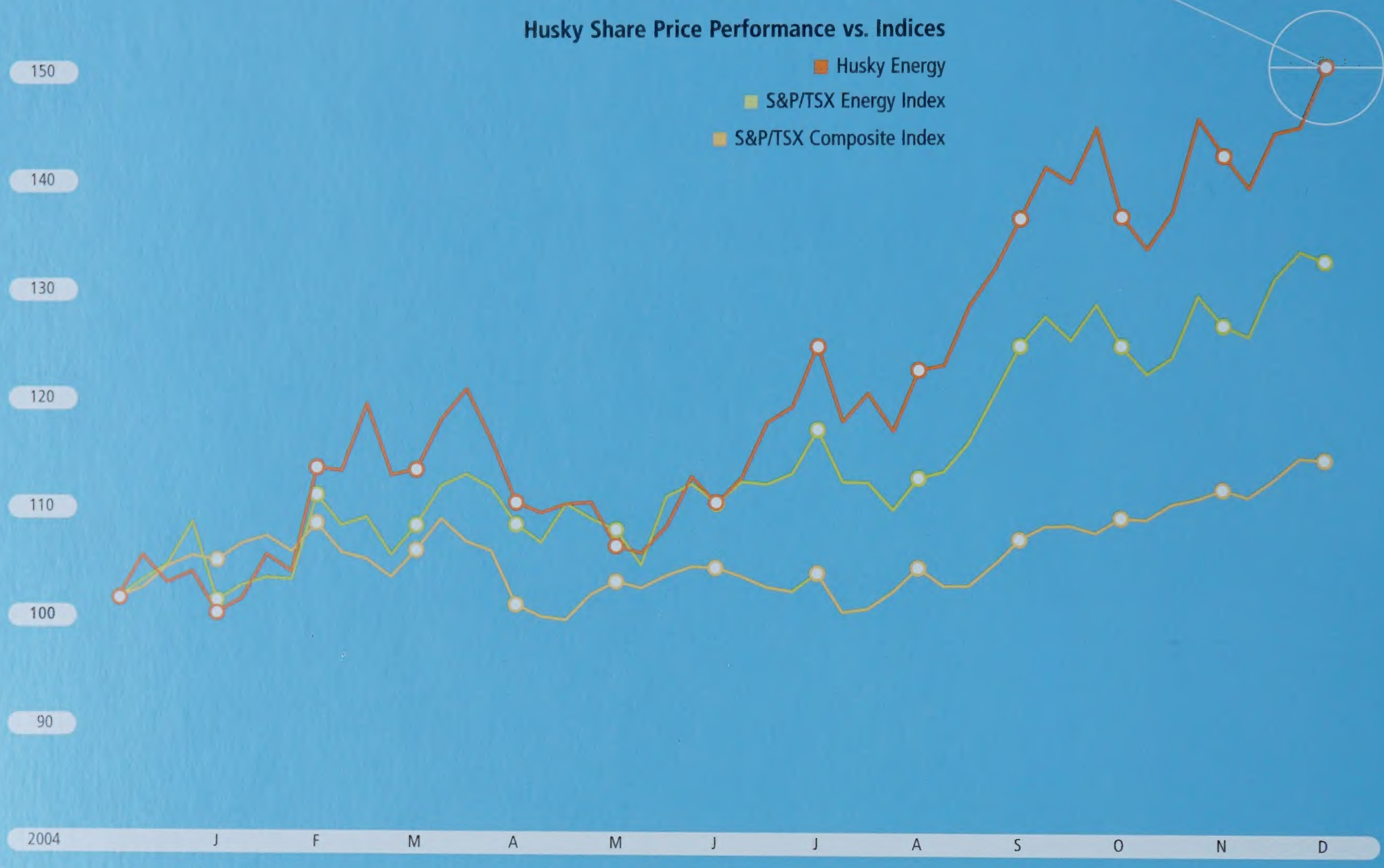
2004



$34.25

Husky Share Price at December 31, 2004
Total Shareholder Return, including ordinary and special dividends, of 50% in 2004
Market Capitalization of $14.5 billion

Husky Share Price Performance vs. Indices



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ON THE COVER

Top: Drilling platform at the Wenchang oil field. Lower Left: Drilling in northern Alberta. Lower Right: *SeaRose FPSO* arriving at Marystown, Newfoundland and Labrador.

UPSTREAM

MIDSTREAM

REFINED PRODUCTS

2005 PLANS

WESTERN CANADA

- Grow Western Canada conventional oil and gas production by 4%
- Achieve production replacement ratio greater than 100%
- Grow heavy oil production up to 10%
- Pursue unconventional gas plays and participate in the drilling of 300 natural gas from coal wells

OIL SANDS

- Commence drilling and facility construction for Tucker Oil Sands Project
- Obtain regulatory approval and progress with front-end engineering for Sunrise Oil Sands Project

CANADA'S EAST COAST

- Drill exploratory wells in Terra Nova Far East block and in South Whale Basin
- Achieve White Rose first oil in late 2005 or early 2006
- Investigate feasibility of developing and transporting gas from White Rose field

INTERNATIONAL

- Additional development drilling in the Wenchang field
- Drill three exploration wells offshore China
- Secure gas sales contract and prepare development plan for Madura BD field, Indonesia

MIDSTREAM

- Upgrader debottlenecking project, including construction, to be 60% complete by end of 2005
- Expand Husky's transmission pipeline to meet demand
- Expand gas storage business by 20%
- Expand commodity marketing volumes to exceed 950,000 boe/day

REFINED PRODUCTS

- Increase fuel volume throughput per location by 3% over 2004
- Increase ancillary income by 4% over 2004
- Complete gasoline portion of the Prince George Refinery Clean Fuels Project
- Complete 80% construction of Lloydminster ethanol plant

UPSTREAM	BUSINESS	STRATEGY

WESTERN CANADA

Business	Strategy
• Crude oil and natural gas development and production	• Increase oil and gas production through exploitation and exploration
• Heavy oil production	• Optimize and expand heavy oil operations
• Natural gas exploration	• Focus on natural gas exploration in the deeper portion of the Western Canada Sedimentary Basin and shallow gas exploration in the plains region

OIL SANDS

Business	Strategy
• Cold Lake and Athabasca oil sands development	• Develop in-situ bitumen resources commencing with Tucker and then Sunrise

CANADA'S EAST COAST

Business	Strategy
• 12.51% interest in Terra Nova oil field	• Participate in continuing development of light oil production from Terra Nova
• 72.5% interest in and operator of White Rose oil field	• Maximize value of White Rose assets
• 2.5 million acres of exploration acreage and holder of 15 Significant Discovery Areas	• Explore White Rose satellite oil opportunities and evaluate gas potential

INTERNATIONAL

Business	Strategy
• 40% interest in Wenchang 13-1 and 13-2 producing oil fields in the South China Sea	• Pursue development opportunities near Wenchang
• 100% interest in six exploration blocks in the South and East China Seas	• Increase resource base through exploration drilling
• 100% working interest in the Madura Block offshore Indonesia	• Increase production from international areas to 10% of total production

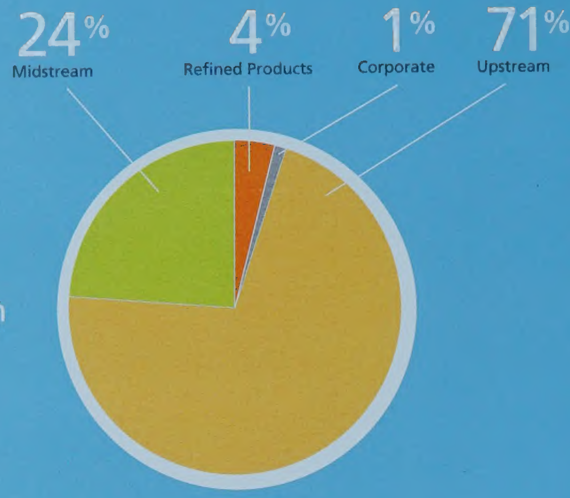
MIDSTREAM

Business	Strategy
• Upgrading of heavy oil into premium synthetic crude oil	• Increase upgrader capacity to meet future heavy oil and bitumen production volumes
• A 2,050-kilometre crude oil pipeline system	• Increase and optimize crude oil pipeline capacity
• Marketing of crude oil, natural gas, natural gas liquids, sulphur and petroleum coke	• Increase value of Husky's assets through growth in the commodity marketing business

REFINED PRODUCTS

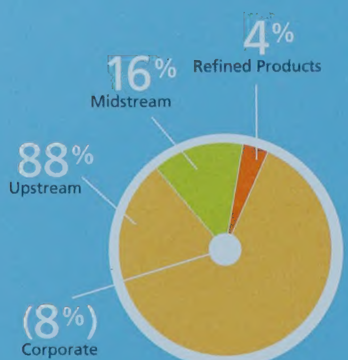
Business	Strategy
• A retail network of over 500 outlets	• Enhance outlets with improvements, upgrades, ancillary sales and alliances
• A 10,000-barrel per day light oil refinery at Prince George, B.C.	• Optimize product supply agreements
• A 25,000-barrel per day asphalt refinery at Lloydminster, Alberta	• Grow asphalt sales through higher margin premium products and new markets
• A 10-million litre per year ethanol plant in Minnedosa, Manitoba	• Expand the use of ethanol in gasoline

2004 PLANS	2004 ACHIEVEMENTS
• Maintain existing drilling program and achieve production replacement ratio greater than 100%	• Increased production 7% to 292 mboe/day and achieved production reserves replacement of 106%
• Continue expanded heavy oil program by drilling 400 to 500 wells	• 420 cold production heavy wells drilled in 2004 • Increased thermal production by 27% to 19,000 bbls/day
• Continue natural gas exploration program and expand exploration into the N.W.T.	• New discoveries made in the Ekwan/Bivouac and Lynx/Copton areas and participated in N.W.T. exploration
• Obtain regulatory approval for Tucker Oil Sands Project and initiate development	• Regulatory approval received and construction initiated at Tucker
• Initiate regulatory approval process for the proposed Sunrise Oil Sands Project	• Regulatory application process initiated for Sunrise • Possible reserves increased 42% to 3.2 billion barrels for Sunrise
• Increase production to 17,500 bbls/day	• Husky's share of production averaged 13,700 bbls/day
• Commission floating production, storage and offloading (FPSO) vessel and continue development drilling	• Topsides installed, hookups and commissioning under way
• Drill one exploration well in South Whale Basin	• South Whale Basin well deferred to 2005 due to rig availability
• Optimize Wenchang production with new development wells	• Drilled three successful Wenchang developmental wells
• Drill at least two exploratory wells offshore China	• One unsuccessful South China Sea well drilled and others delayed due to unavailability of rigs
• Continue negotiations of new gas sales contract	• Acquired partner's share in Madura Block
• Continue with debottlenecking projects and improve operating efficiencies	• Engineering for debottlenecking project is 60% complete
• Exploit strategic position of assets in the heavy oil/bitumen corridor	• Husky begins blending the new Western Canada Select crude oil stream
• Expand marketing volumes to over 900,000 boe/day	• Commodity Marketing volumes exceeded 900,000 boe/day
• Increase throughput volumes per outlet	• Average throughput volume per outlet increased 8.3% over 2003
• Finalize Clean Fuels Project decision to meet new environmental regulations and expand throughput	• Committed capital funds to produce low sulphur gasoline and diesel, and expand refinery throughput to 12,000 bbls/day
• Encourage adoption of higher asphalt specifications	• Set new asphalt sales record of 22,800 bbls/day
• Initiate construction of a 130-million litre per year ethanol plant at Lloydminster, SK	• Construction commenced

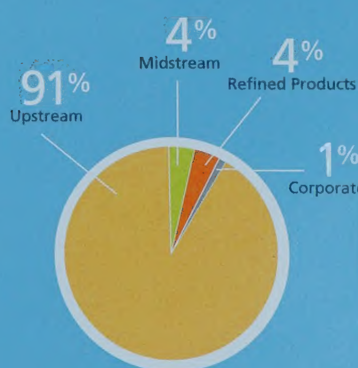


$1.0 billion
NET EARNINGS

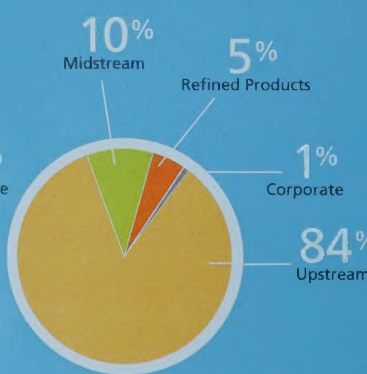
2004 PERFORMANCE



$2.2 billion
CASH FLOW FROM OPERATIONS



$2.4 billion
CAPITAL EXPENDITURES



$13.2 billion
TOTAL ASSETS

Year ended December 31 (millions of dollars except where indicated)		2004	2003	2002
FINANCIAL HIGHLIGHTS				
Sales and operating revenues, net of royalties		**8,440**	7,658	6,384
Cash flow from operations		**2,223**	2,459	2,096
Per share *(dollars)* – Basic		**5.19**	5.79	4.94
– Diluted		**5.16**	5.76	4.92
Net earnings		**1,006**	1,334	814
Per share *(dollars)* – Basic		**2.37**	3.26	1.91
– Diluted		**2.36**	3.25	1.90
Capital expenditures (1)		**2,379**	1,902	1,707
Return on average capital employed	*(percent)*	**12.8**	18.1	12.3
Return on equity	*(percent)*	**16.2**	24.1	16.9
Debt to capital employed	*(percent)*	**22.5**	23.0	31.7
Debt to cash flow from operations	*(times)*	**0.8**	0.7	1.1
OPERATING HIGHLIGHTS				
Daily production, before royalties				
Light crude oil & NGL	*(mbbls/day)*	**66.2**	71.6	65.4
Medium crude oil	*(mbbls/day)*	**35.0**	39.2	44.8
Heavy crude oil	*(mbbls/day)*	**108.9**	99.9	95.1
Total crude oil & NGL	*(mbbls/day)*	**210.1**	210.7	205.3
Natural gas	*(mmcf/day)*	**689.2**	610.6	569.2
Barrels of oil equivalent	*(mboe/day)*	**325.0**	312.5	300.2
Proved reserves, before royalties				
Light crude oil & NGL	*(mmbbls)*	**238**	223	235
Medium crude oil	*(mmbbls)*	**86**	94	107
Heavy crude oil (2)	*(mmbbls)*	**105**	227	227
Natural gas	*(bcf)*	**2,169**	2,059	2,095
Barrels of oil equivalent	*(mmboe)*	**791**	887	918
Synthetic crude oil sales	*(mbbls/day)*	**53.7**	63.6	59.3
Pipeline throughput	*(mbbls/day)*	**492**	484	457
Light oil sales	*(million litres/day)*	**8.4**	8.2	7.7
Asphalt product sales	*(mbbls/day)*	**22.8**	22.0	20.8
Refinery throughput	*(mbbls/day)*	**35.1**	36.0	32.1

(1) Excludes capitalized costs related to asset retirement obligations incurred during the period and corporate acquisitions.
(2) For 2004, includes a negative non-technical revision for year-end heavy oil pricing of 120 mmbbls.

MISSION To maximize returns to our shareholders in a socially responsible manner.

VISION To create superior shareholder value through financial discipline and a quality asset base.

CORPORATE PROFILE Husky Energy is a Canadian integrated energy and energy related company. Our operations consist of three business segments: upstream, midstream and refined products.

The upstream segment includes the exploration, development and production of crude oil and natural gas. Operations are focused in Western Canada, offshore the Canadian East Coast, in the South and East China Seas, offshore Indonesia and other international areas.

Midstream includes the upgrading of heavy crude oil into premium quality synthetic crude oil, pipeline transportation, gas storage, cogeneration, and commodities marketing including crude oil, natural gas, natural gas liquids, sulphur and petroleum coke.

Refined products activities comprise the refining, marketing and distribution of gasoline, diesel, asphalt, ethanol, and ancillary services in Canada and the United States, and a network of over 500 retail outlets from Ontario to British Columbia and the Yukon.

Husky Energy Inc. is headquartered in Calgary, Alberta, Canada and is listed on the Toronto Stock Exchange under the symbol HSE.

HUSKY ENERGY REPORT TO OUR SHAREHOLDERS

BUILDING ON THE HORIZON

Mr. Victor T. K. Li (upper left) Co-Chairman
Mr. Canning K. N. Fok (upper right) Co-Chairman
Mr. John C. S. Lau (left) President & CEO

We are pleased to report another successful year for Husky Energy in 2004. Increased natural gas production and high commodity prices contributed to the strong financial results, with net earnings exceeding $1 billion for the second consecutive year. Return on equity of 16.2 percent was above our target of 15 percent and we were able to declare a special dividend of 54 cents per share in November, allowing shareholders to benefit directly from the Company's financial performance.

2004 was notable for the continuing strength in commodity prices, with West Texas Intermediate (WTI) rising throughout the year to an average of U.S. $48.28 per barrel in the fourth quarter. With the expiration of our crude oil hedging program at year-end, Husky is well positioned to reap the benefit of future strength in commodity markets.

The impact of higher oil and gas prices was partly offset by the continued weakness of the U.S. dollar which ended the year at Canadian $1.20 compared with $1.29 at the start. The Company's U.S. dollar denominated debt offers a partial hedge of our revenue exposure.

Several production records were achieved in 2004. Gas production of 689 million cubic feet per day was up 13 percent from 2003. Heavy oil averaged 108,900 barrels per day, a nine percent improvement from the previous year. In the Refined Products segment, light oil sales grew to an average of 8.4 million litres per day with sales per outlet up from 10,800 to 11,700 litres per day. Asphalt sales also reached a record level in 2004, averaging 22,800 barrels per day.

The White Rose project passed several key milestones during the year. In January, the floating production, storage and offloading vessel (FPSO) was named the *SeaRose FPSO,* at a ceremony in South Korea. The *SeaRose FPSO* arrived at Marystown, Newfoundland and Labrador in April, where the topside modules were installed. In July, the first production

well was successfully tested with an estimated production capability of between 25,000 and 35,000 barrels per day, exceeding expectations.

The Company is moving towards phased development of its major oil sands assets in Northern Alberta. In July, regulatory approval was received for commercial development of the Tucker Oil Sands Project. With an expected production rate of 30,000 barrels per day or more, the project is expected to recover 352 million barrels over a 35-year life. In August, a lump sum contract was entered into for the central processing facility; construction began in September with commissioning planned for late 2006.

Husky also submitted a regulatory application for commercial development of its Sunrise Oil Sands lease. Corporate and regulatory approvals for Sunrise are anticipated in 2006. Development of this massive resource forms part of Husky's long-term growth plans, and optimization of production, upgrading and transportation options will be a priority in 2005.

Internationally, Husky continued to build up its position in China and Indonesia. A sixth exploration contract was signed for the 29/26 exploration block in the South China Sea. A well is planned for 2005, subject to rig availability. In Indonesia, Husky bought out its partner's interest in an offshore production-sharing contract in the Madura Strait, giving the Company a 100 percent interest in the Madura BD and MDA gas discoveries, as well as several exploration prospects. The Company's focus in 2005 will be on securing a long-term gas sales contract for the BD gas field.

Husky aims to become the largest ethanol producer in Western Canada and 2004 saw construction commence on a 130-million litre per year plant at Lloydminster, Saskatchewan. The plant, which is expected to be operational in early 2006, will help meet the demand for environmentally friendly fuels as well as encouraging rural development and the agricultural industry. The facility will benefit from cost synergies with the adjacent upgrader complex.

At the Company's Prince George light oil refinery, the Clean Fuels project was initiated. This project is designed to meet new environmental requirements for cleaner gasoline and diesel fuels, as well as increase throughput capacity from 10,000 to 12,000 barrels per day.

Husky ended 2004 in a strong financial position with a debt to cash flow from operations ratio of less than one. In 2005, Husky has a planned capital expenditure program of $2.545 billion and forecasts production at 325,000 to 350,000 barrels of oil equivalent per day. With the White Rose and Tucker Projects expected to be on schedule, the Company is moving confidently towards its medium-term production target of 500,000 barrels of oil equivalent per day.

2004 was an exciting year for Husky. Our Company's achievements could not have been made without the commitment, skill and enthusiasm of our management team and employees, and the ongoing encouragement of our shareholders. On behalf of the Board of Directors, we express our deep appreciation for their contributions.

Victor T. K. Li	Canning K. N. Fok	John C. S. Lau
Co-Chairman	*Co-Chairman*	*President & Chief Executive Officer*

Husky's shareholders continue to share in the performance of their company. In April 2004, the quarterly dividend was increased from $0.10 to $0.12 ($0.48 annually) per common share, and in November a special cash dividend of $0.54 per common share was approved by the Board of Directors. Total return to shareholders, including stock price appreciation and special and ordinary dividends, exceeded 50 percent for the second consecutive year. John C.S. Lau discusses Husky's strategies, achievements and challenges.

ANSWERS FROM JOHN C.S. LAU, PRESIDENT & CEO

QUESTIONS & ANSWERS

Q: Husky achieved its production guidance in 2004. What is your production guidance in 2005?

A: Production for 2004 was in the range announced in December 2003. The 2005 guidance reflects stable volumes from existing producing assets. A significant increase in production will occur when White Rose comes on stream followed by the Tucker oil sands and other longer-term projects. The Company's medium-term goal is to achieve a production level of 500,000 barrels of oil equivalent per day.

Daily production before royalties		*2004 Guidance*	*2004 Actual*	*2005 Guidance*
Light crude oil & NGL	*(mbbls/day)*	67 – 76	66.2	64 – 71
Medium crude oil	*(mbbls/day)*	35 – 40	35.0	32 – 36
Heavy crude oil	*(mbbls/day)*	105 – 115	108.9	112 – 120
Natural gas	*(mmcf/day)*	670 – 710	689.2	700 – 740
Barrels of oil equivalent (6:1)	*(mboe/day)*	320 – 350	325.0	325 – 350

Q: How have the U.S. Securities and Exchange Commission's requirements for reserve reporting affected Husky's proved heavy oil reserves?

A: Husky's proved oil and natural gas reserves are estimated in accordance with the regulations of the U.S. Securities and Exchange Commission, which require proved reserves to be evaluated for economic recoverability using well head prices in effect on the day of estimation. Although prices for heavy crude oil averaged $25.91 per barrel in the fourth quarter of 2004, as a result of several market factors the price on December 31, 2004 was only $12.27 per barrel.

The resulting negative revision of 120 million barrels to proved heavy oil reserves took no account of the offsetting beneficial impact of lower feedstock prices on Husky's heavy oil upgrading and refining operations, and had no impact on the Company's financial results.

Q: Has Husky added to its oil and gas reserves to support its long term production growth targets?

A: At December 31, 2004, Husky's total proved oil and gas reserves, excluding the negative revision of 120 million barrels to heavy oil reserves, amounted to 911 million barrels of oil equivalent, giving the Company a proved reserve life of eight years.

In Western Canada, Husky replaced 106 percent of production in 2004, excluding the negative heavy oil price revision.

The White Rose field contains 165 million barrels of proved plus probable oil reserves, which will be converted to proved as the project is developed. The White Rose area also contains additional possible reserves of 145 million barrels of oil together with 1.7 trillion cubic feet of gas to Husky. Tucker adds a further 79 million barrels of probable reserves and 273 million barrels of possible reserves. Sunrise contributes 3.2 billion barrels of possible reserves over the longer term.

Internationally, the Company should increase its proved reserves once a sales contract has been negotiated for natural gas production from its Madura block, in Indonesia, and an extension to the production sharing contract has been obtained.

We also expect to continue to add new reserves through exploration and corporate acquisitions.

Q: How is Husky dealing with the challenge of wider heavy/light oil price differentials?

A: Husky's ownership of the asphalt refinery and heavy oil upgrader at Lloydminster provides a natural hedge against wider differentials by converting heavy oil into higher value products. Husky has initiated a series of debottlenecking projects at the upgrader to increase throughput capacity to 82,000 barrels per day by 2006. We are evaluating options to add further upgrading capacity as well as the shipping of heavy oil and bitumen to the West Coast for transportation to new export markets.

Q: How is Husky's strategy for developing its oil sands holdings proceeding?

A: Husky is currently developing two major oil sands assets, Tucker and Sunrise, using steam assisted gravity drainage (SAGD) technology. Our strategy is to apply our thermal extraction experience acquired from developing our heavy oil assets in the Lloydminster area.

The Tucker Oil Sands Project has synergies with our infrastructure in the area. Husky can move its production to the Lloydminster Upgrader via our pipeline system. From Lloydminster, the synthetic oil can be shipped through our terminal in Hardisty, to refineries in Canada and the U.S. for further processing.

We are progressing with conceptual engineering and environmental approvals for the much larger Sunrise Oil Sands Project. Sunrise will benefit from the experience we have acquired from Tucker and other SAGD projects. At the same time we are reviewing midstream and downstream solutions for upgrading, transportation and processing.

Q: [illegible]

A: Cost overruns can have a significant impact on the economic viability of large projects. To support timely completion of projects within budget the Company has in place business processes and controls to manage all key project elements. A critical factor in a project's success is to complete the necessary conceptual and front-end engineering work, followed by detailed design before any major contracts are issued.

On Tucker and other major projects we have applied a strategy of lump sum contracts where appropriate to provide better cost certainty.

We have also created the position of Vice President, Engineering and Project Management, responsible for facilities engineering and execution of major projects.

Q: [illegible]

A: Husky's growth strategy is based on the development of an existing diverse asset base. We have an ongoing review of strategic alternatives to enhance shareholder value, including financial restructuring, mergers, acquisitions and sales.

Q: [illegible]

A: Husky plans to export natural gas from White Rose if economically feasible. Our initial review of likely technologies indicates that a marine transportation system using compressed natural gas or pressurized natural gas may be the preferred solution. We've invited three companies, selected from 40 Canadian and international firms, to submit feasibility studies in the first quarter of 2005.

Husky initiated the process in 2004 by soliciting expressions of interest from firms to assess the key technical, economic and regulatory issues critical to a safe and reliable natural gas development on the Grand Banks, as well as the capital and operating costs of such a development.

Q: Why is Husky developing a natural gas from coal (NGC) drilling program through a joint venture?

A: Husky has over 6.5 million acres of undeveloped land in Western Canada, much of it potentially suitable for the production of natural gas from coal. The economic feasibility of NGC production has improved due to a better understanding of coal geology, production technology and higher natural gas prices. We have studied NGC feasibility for several years and have entered into a joint venture development with a company that has demonstrated strong expertise in NGC production.

Q: Why is Husky expanding its ethanol production?

A: Husky aims to become Western Canada's largest ethanol producer. This goal supports Husky's efforts to promote the use of ethanol-blended gasoline and demonstrates the Company's commitment to growth in a socially responsible manner.

We currently produce 10 million litres per year at our ethanol plant in Minnedosa, Manitoba, and have started construction on a 130-million litre per year plant at Lloydminster, Saskatchewan. The plant is expected to be operational in the first quarter of 2006.

Our plans include the possible development of two more ethanol plants; one in Minnedosa to replace the existing plant, and another in Prince George, British Columbia.

Q: Has Husky hedged any of its production in 2005?

A: Husky's current crude oil hedging program ended on December 31, 2004, and the Company has not entered into any further hedges. For more information on Husky's hedging, please refer to the disclosure in Note 19 to the Consolidated Financial Statements.

Q: Will Husky be declaring another special dividend in 2005?

A: It is at the Board of Directors' discretion to determine if Husky is in a position to provide a special cash dividend to our shareholders. In each of the past two years the Board has declared a special dividend to enable shareholders to benefit directly from the financial performance of the Company. The Board will continue to monitor the Company's cash requirements for our ongoing operations as well as capital expenditures for our major projects.

WESTERN CANADA

A major part of Husky's production, development and exploration is in the Western Canada Sedimentary Basin. Growth plans include the drilling of deeper gas prospects and the development of our heavy oil holdings.

OIL SANDS

The oil sands in northern Alberta are one of Husky's long-term growth areas.

CANADA'S EAST COAST

Canada's East Coast will play a key role in achieving Husky's medium-term production targets. The Company holds significant exploration acreage on the Grand Banks, 12.51 percent interest in the producing Terra Nova oil field, and 72.5 percent of the White Rose oil field currently nearing completion.

INTERNATIONAL

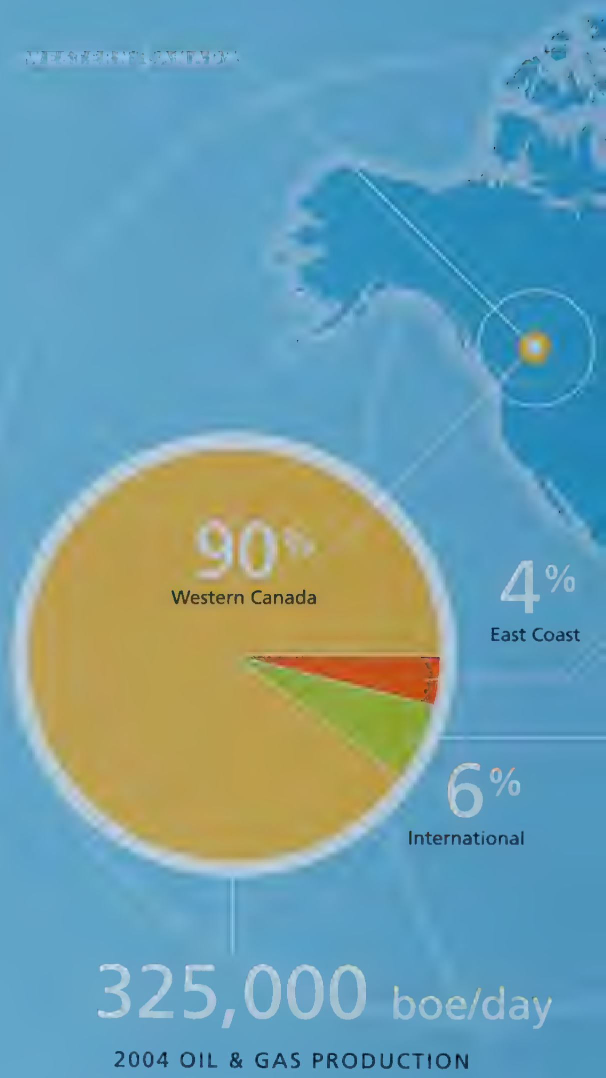
Husky's holdings in the Wenchang oil field in the South China Sea, exploration blocks offshore China, and a development opportunity in Indonesia's Madura Strait provide a strong base for expanding our international operations.

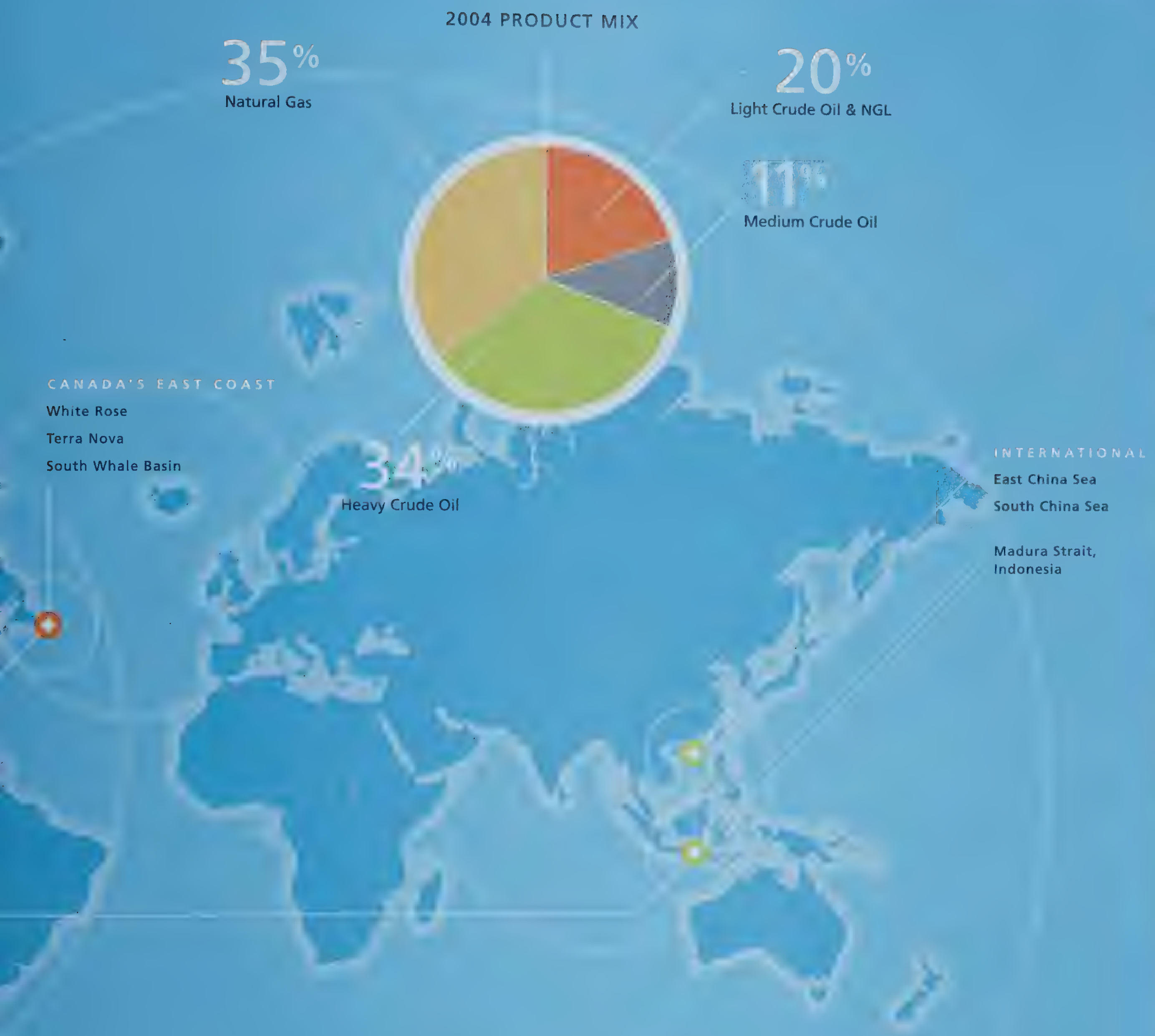
MIDSTREAM

The Company's midstream operations are critical to our strategy of exploiting synergies among our business segments and reducing the volatility of our cash flow. They include heavy oil upgrading, pipeline systems, commodity marketing, electricity cogeneration, crude oil and natural gas storage, and processing.

REFINED PRODUCTS

Refined Products focuses on the refining, marketing and distribution of gasoline, diesel, asphalt, ethanol and ancillary services. Many of these products are marketed through our retail network under the Husky and Mohawk brands.

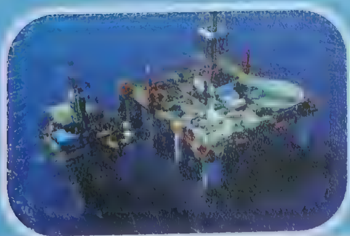


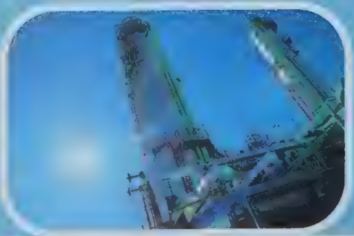


REPORT ON OPERATIONS

BUILDING ON THE HORIZON

Husky is one of Canada's largest energy companies. During the past decade we have emphasized financial discipline while building substantial growth opportunities in Alberta's heavy oil and bitumen corridor, and offshore Canada's East Coast and China.





Working interest:
72.5 percent

Husky's share:
- Proved and probable reserves: 165 mmbbls
- Peak production: 67,500 bbls/day

Number of wells:
19 – 21

Field life:
10 – 15 years

First oil:
late 2005 or early 2006

EAST COAST CAPITAL EXPENDITURES

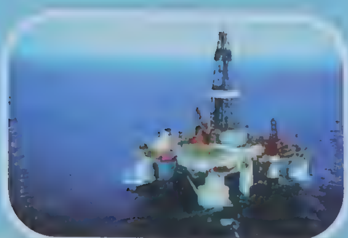
OUTLOOK

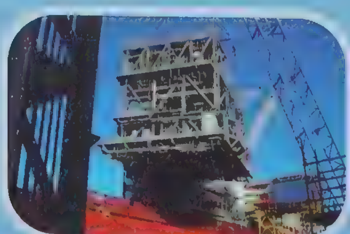
Terra Nova
- Husky's share in 2005 is anticipated to average 14,000 – 16,000 barrels per day

White Rose
- *SeaRose FPSO* is expected to sail to the White Rose field in the third quarter of 2005
- First oil production in late 2005 or early 2006
- Evaluate proposals for developing and transporting natural gas

Exploration
- Evaluate holdings in the Jeanne d'Arc and South Whale Basins

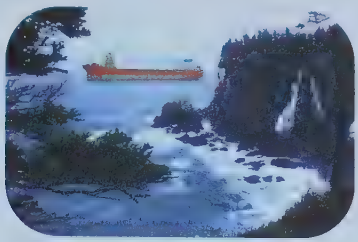
Left: *SeaRose FPSO arriving at Marystown*
Lower Left: *Glomar Grand Banks drilling rig at the White Rose oil field*
Lower Centre: *Installing topside modules on the SeaRose FPSO*
Lower Right: *Turret on SeaRose FPSO*





OFFSHORE CANADA'S EAST COAST

WHITE ROSE – NEARING COMPLETION



The White Rose project offers great potential for Husky. Plans have the SeaRose FPSO sailing for the White Rose field in the third quarter of 2005 and we should have first oil by the end of 2005 or in early 2006. Once White Rose is commissioned, we anticipate that production will average 92,000 barrels per day, 67,500 net to Husky. – *W. (Walt) DeBoni, Vice President, Canada Frontier & International Business*

Husky's operations off Canada's East Coast will play a key role in achieving our growth targets. We are the operator of the White Rose development in the Jeanne d'Arc Basin, own a 12.51 percent interest in the Terra Nova field, and have substantial exploration holdings on the Grand Banks.

WHITE ROSE

Husky's immediate plans are to complete the White Rose Project and define additional development opportunities in the field, including the delineation of other oil reserves and the feasibility of natural gas production. Our long-term strategy is to maximize the utilization of the White Rose production facility by developing the oil and gas resources in the area.

In April, the hull of the *SeaRose FPSO* arrived in Marystown, Newfoundland and Labrador, from South Korea. The lifting and installation onto the hull of 17 topside modules was completed on schedule by the end of July, while work on hookups and commissioning continues. The mooring installation and buoy hookups were completed, and subsea installation of flowlines will carry on into 2005. The first production, water and gas injection wells were completed and tested.

During the year Husky commenced feasibility studies on developing natural gas from the White Rose field, which has possible reserves of 1.7 trillion cubic feet. Three companies have undertaken to submit proposals for producing and transporting natural gas to Husky in the first quarter of 2005.

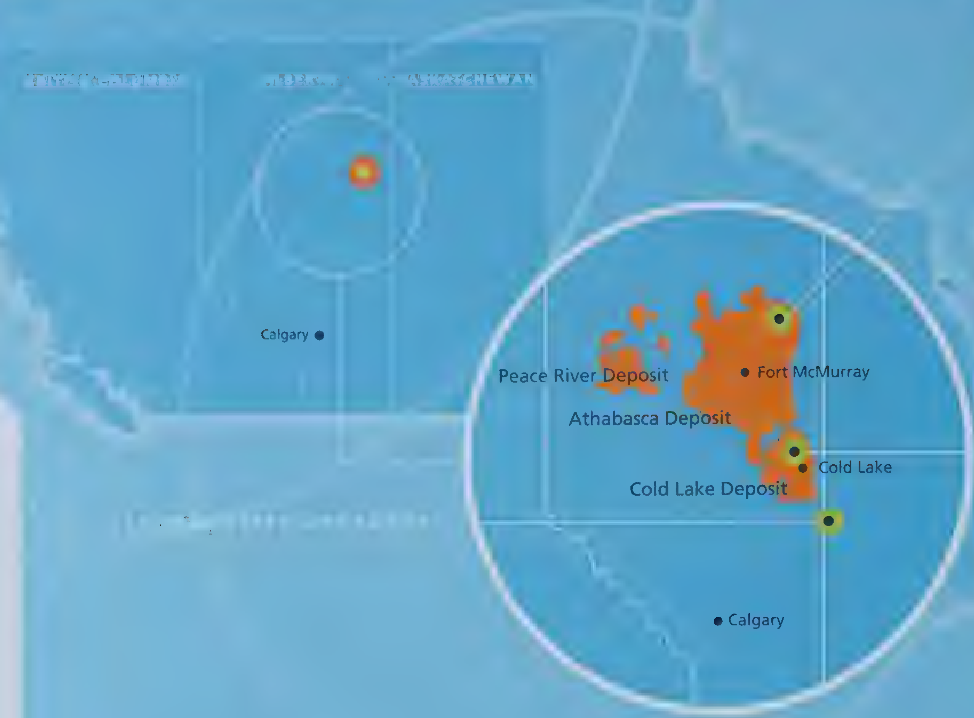
TERRA NOVA

At the end of 2004, remaining proved reserves were estimated at 24 million barrels and probable at 14 million barrels. Husky's share of production averaged 13,700 barrels of oil per day in 2004. During the year, several development wells were drilled.

EXPLORATION

Husky believes that the Grand Banks holds significant long-term potential. We have identified several oil prospects in proximity to White Rose that could be tied back to the *SeaRose FPSO* to extend production life, as well as gas prospects.

Depending upon rig availability, Husky plans to drill its Lewis Hill prospect in the South Whale Basin where we have a 100 percent working interest.



SUNRISE

- Working interest: 100 percent
- Possible reserves: 3.2 billion bbls
- Peak production: up to 200,000 bbls/day

TUCKER

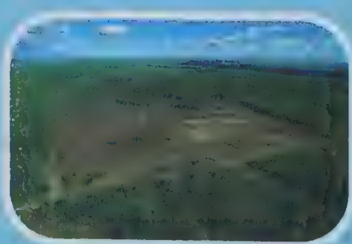
- Working interest: 100 percent
- Capital cost to first oil: $500 million
- Contract: Lump sum for central processing facility
- First production: 3 to 6 months after commissioning in Q3 of 2006
- Probable and possible reserves: 352 million bbls

OUTLOOK

Husky's oil sands strategy is to establish commercial in-situ bitumen production first at Tucker, and to develop Sunrise in coordination with the expansion of required infrastructure and development of downstream solutions.

Assessment of our other leases is under way and we expect to make decisions on their commercialization within the next two to three years.

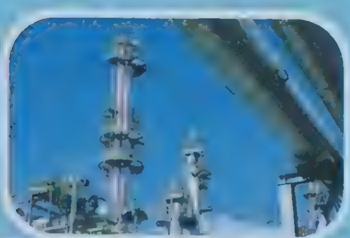
Lease	Original Bitumen in Place
Tucker	1,270 mmbbls
Sunrise	10,600
Caribou	2,500
Saleski	16,800
Others	2,380
Total	**33,550 mmbbls**



Left: *Aerial view of the Tucker Oil Sands site*

Lower Centre: *Drilling of well pads*

Lower Left and Right: *Husky's heavy oil upgrader can process bitumen from Tucker*



ALBERTA'S OIL SANDS

MASSIVE RESOURCE POTENTIAL

Husky's Tucker and Sunrise holdings are very high quality oil sands resources. Add to that our thermal heavy oil experience, upgrading and refinery operations, commodity and refined product marketing expertise, project execution skills, and financial discipline, and you have a company with the capabilities to maximize the value of its oil sands assets. – R.L. (Bob) Shepherd, General Manager, Oil Sands

The oil sands of northern Alberta are one of Husky's long-term growth areas. The Company has more than 425,000 acres in the Athabasca, Cold Lake and Peace River areas that contain over 33 billion barrels of bitumen in place. Our first two projects are Tucker and Sunrise.

TUCKER

Husky announced corporate approval to proceed with commercial development of our Tucker Oil Sands Project, 30 kilometres northwest of Cold Lake, Alberta, in July 2004. During the 35-year project life we expect to recover 352 million barrels using a steam assisted gravity drainage (SAGD) process.

Construction began in the fall of 2004 and facility commissioning is anticipated in late 2006. First oil production will commence within three to six months thereafter. Production from the project is expected to be 30,000 barrels per day or more.

SUNRISE

The Sunrise Oil Sands Project is 60 kilometres northeast of Fort McMurray, Alberta. Covering 58,000 acres, it is estimated that the project could produce 3.2 billion barrels of bitumen over a 40-year life span. The increase in possible reserves from 2003 reflects a re-evaluation of the geological and reservoir data.

Excellent reservoir quality and an average pay thickness of over 40 metres in the first phase area of the project are expected to yield low steam-to-oil ratios and lower unit operating costs.

An application to provincial regulators was submitted in August 2004 for approval to proceed with a 200,000-barrel per day project to be developed in phases. Husky is currently carrying out the necessary conceptual and development engineering work to establish the optimal development and upgrading solutions for the project.

OUTLOOK

China

- Provide additional development drilling at Wenchang
- Continue exploration on existing blocks

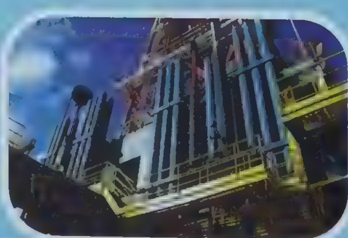
Indonesia

- Negotiate new natural gas sales contract for Madura BD production
- Negotiate an extension to the production-sharing contract term
- Pursue exploration potential on Madura Strait block

- Working interest: 40 percent
- Husky's share:
  - Proved and probable reserves: 22 million bbls
  - 2004 average production: 19,700 bbls/day
- Number of wells: 24
- Field life: 10-12 years
- First oil: July 2002

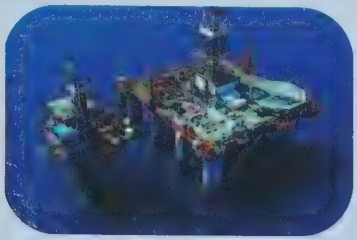
Left: *Floating production, storage and offloading vessel at Wenchang oil field*

Lower Left, Centre and Right: *Drilling platform at Wenchang oil field*



AN INTERNATIONAL PORTFOLIO

EXPANDING OPERATIONS



The maturing of many hydrocarbon-producing basins in North America means that companies must move into more remote and geologically challenging regions of the world to seek new conventional oil and gas reserves. In this regard, Husky is pursuing exploration and development opportunities in China, Indonesia and elsewhere. – *D. R. (Dave) Taylor, Vice President, Exploration*

CHINA

The Company has been successful in building from our production base at Wenchang in the South China Sea. Since acquiring an interest in Wenchang in 2002, Husky has acquired six exploration blocks in the South China Sea and the East China Sea, and is well positioned with good exploration prospects near major markets in China.

In August, we signed a petroleum contract with the China National Offshore Oil Corporation for the 29/26 exploration block in the South China Sea, located 300 kilometres southeast of Hong Kong. Under the terms of our contract, Husky will drill an exploration well on the block, the timing of which is subject to rig availability.

We plan to drill two exploration wells on our 23/15 and 23/20 blocks in the shallow water Beibu Gulf in 2005. The blocks are located 450 kilometres southwest of Hong Kong, near Hainan Island.

INDONESIA

Husky is also positioned for growth in Indonesia with the acquisition of the balance of an interest in a production-sharing contract in the Madura Strait. The transaction gives Husky a 100 percent interest in the block where two natural gas fields have been discovered; Madura BD and MDA, and several exploration opportunities have been identified.

The BD field has probable reserves of 167 billion cubic feet of natural gas and nine million barrels of oil and natural gas liquids based on the current term of the production-sharing (PSC) agreement. Husky anticipates that an additional 348 billion cubic feet of natural gas and 14 million barrels of natural gas liquids will be classified as probable reserves with the signing of an extension to the PSC.

Development of BD would involve installing an unmanned production platform and constructing a pipeline to new onshore gas processing facilities. Peak production is estimated to be 80 million cubic feet per day. After the signing of the PSC extension and finalization of a gas supply contract, the development is expected to come on-stream within three years.

The MDA field has discovered resources of 150 billion cubic feet and additional exploration prospects are being evaluated for future drilling in the area.

HEAVY OIL

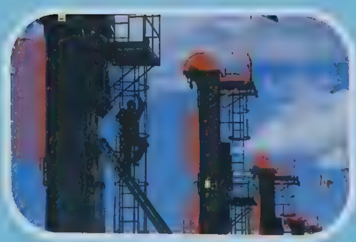
108.9
(mbbls/day)

DAILY PRODUCTION, BEFORE ROYALTIES – HEAVY CRUDE OIL

OUTLOOK

- Grow heavy oil production by up to 10%
- Drill 400 to 500 primary heavy oil wells
- Seek new opportunities to implement thermal recovery technology
- Focus on operating and capital cost control

- Average working interest: 93 percent
- 2004 average production: 108,900 bbls/day
- Total proved reserves: 205 mmbbls (excluding non-technical revision for year-end heavy oil pricing)
- Landholdings: 1.57 million acres



Left: *Bolney/Celtic thermal oil processing plant*

Lower Left: *Drilling of new primary heavy oil wells*

Lower Centre and Right: *Synergies between heavy oil and refining*

HEAVY OIL

BUILDING ON HUSKY'S CORE POSITION

Heavy oil is a production business that requires not only the technology but the discipline to control both capital and operating costs to make a profit. Heavy oil development will continue to play an important role in Husky's production growth. We aim to grow our heavy oil production by ten percent per year through the drilling of primary heavy oil wells, and the development of new thermal projects. -- *R.S. (Bob) Coward, Vice President, Western Canada Production*

LLOYDMINSTER

Husky has been a pioneer in the development and production of heavy oil in Western Canada. The Company's extensive heavy oil holdings in the Lloydminster area play a very significant role in our Western Canada energy portfolio where our heavy oil production, Lloydminster upgrader and pipeline system create synergies across the value chain, from production and transportation to upgrading and refining.

As part of Husky's strategy we increased the number of primary heavy oil wells drilled. This strategy has continued to be successful with 420 net wells drilled in 2004, an increase of 15 percent over 2003. Primary cold production increased to 77,300 barrels per day, up from 71,000 per day in 2003.

BOLNEY/CELTIC

Our thermal operations at Bolney/Celtic in Saskatchewan continue to meet expectations. By the end of 2004, the combined Bolney/Celtic development was producing over 10,000 barrels of oil per day. We completed Stage Two of our three-stage plan and have approved construction of Stage Three to increase production to 13,500 barrels per day, in the third quarter of 2005. Combined with production from Pikes Peak and Lashburn in Saskatchewan, Husky's total thermal production was 19,000 barrels per day in 2004.

MAXIMIZING PRIMARY HEAVY OIL PRODUCTION

Husky is continuously looking at technologies and business processes to maximize its heavy oil production. The Company has initiated a pump optimization program that focuses on reducing the frequency of pump failures due to equipment or well inflow changes. Root cause failure analysis is used to determine the origin of the problem and apply a solution to ensure that it does not occur again.

The Company has also installed single-well monitoring technology, which tracks and analyzes key production indicators at 2,000 well sites. The sites are monitored on a 24-hour basis from a central location where operators can review performance and intervene on well problems.

689.2
(mmcf/day)

DAILY PRODUCTION, BEFORE ROYALTIES – NATURAL GAS

OUTLOOK

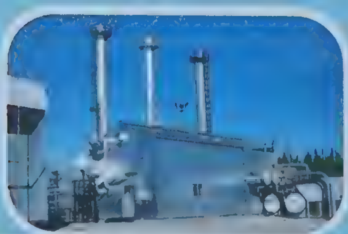
- Minimize operating costs
- Fully load our production infrastructure and farm out inactive lands
- Maintain reserve replacement over 100 percent
- Sustain an average reinvestment ratio of 60 to 70 percent

- Average working interest: 90 percent
- 2004 average daily production:
  - Light oil – 33,000 bbls/day
  - Medium oil – 35,000 bbls/day
  - Natural gas – 689 mmcf/day
- Western Canada oil and gas landholdings: 9.6 million acres

Left: *Drilling a gas well in the Shackleton area*

Lower Left and Centre: *Kakwa gas plant was acquired in 2003*

Lower Right: *Husky's Ram River Gas Plant*



CONVENTIONAL OIL AND GAS

INCREASING NATURAL GAS PRODUCTION

In a mature basin such as Western Canada, one needs to be a significant player with drilling, infrastructure, and geological and geophysical synergies in core areas to pursue gas and oil opportunities. During the year Husky embarked on developing natural gas from coal, increased volumes at our Viking gas projects, and added to our gas reserves in northeastern British Columbia. – R. S. (Bob) Coward – Vice President, Western Canada Production

PRODUCTION

Husky's objective in 2005 is to grow our Western Canadian natural gas production to a range of 700 to 740 million cubic feet per day. Our strategy consists of drilling low-risk shallow gas prospects in the northwestern Alberta plains, and in southern Alberta and Saskatchewan that exploit our existing infrastructure, as well as higher-risk, higher-reward deep gas prospects in the foothills of British Columbia and Alberta.

Husky has explored and developed the Bivouac, Ekwan and Titan areas of northeastern British Columbia during the past three years, adding proved reserves of 111 billion cubic feet of natural gas. Husky plans to drill and tie-in 37 wells in this area and double production to 40 million cubic feet per day.

Our natural gas development near Craigend, Alberta is our most successful development in the Viking formation. Average production during 2004 was 15 million cubic feet per day, and we increased our landholdings in the area to 140,000 acres. Husky plans to increase production to 20 million cubic feet per day by drilling 50 wells in 2005.

The Moose Mountain/McLean Creek gas development west of Calgary continues to show good potential. During 2004, two gas wells were tied in at Moose Mountain and two gas wells were drilled at McLean Creek resulting in proved natural gas reserves increasing to 32 billion cubic feet and proved liquids to 3.6 million barrels. The tie-in of these wells in April 2005 will increase Husky's share of production to 20 million cubic feet of natural gas and 1,900 barrels of liquids per day.

EXPLORATION

Husky plans to drill over 200 exploratory wells in 2005, targeting a variety of plays in the foothills, deep basin, northeastern British Columbia and Alberta plains.

We will also seek opportunities for extracting natural gas from coal (NGC) that utilize our existing infrastructure. This offers Husky the potential to grow gas volumes from our existing east central and southern Alberta leases. We increased net daily volumes to five million cubic feet in 2004. We plan to participate in drilling 300 wells during 2005 to increase net NGC production to over 30 million cubic feet per day.

MIDSTREAM ASSETS

OUTLOOK

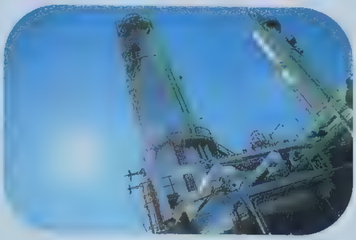
- Increase Husky's natural gas storage business
- Expand Husky's transmission pipelines
- Complete construction facilities at the Hardisty terminal to handle Western Canada Select blend
- Progress Lloydminster upgrader debottlenecking project

- Upgrader capacity: 77,000 bbls/day
- Pipeline system: 2,050 km
- Pipeline storage: 2.3 mmbbls
- Natural gas storage: 20 bcf
- Cogeneration:
  - 50 percent interest in a 215 MW facility at Lloydminster, Saskatchewan
  - 50 percent interest in a 90 MW facility at Rainbow Lake, Alberta

Left and Lower Right: *Natural gas storage at Husky's Hussar storage facility*
Lower Left: *Husky's Lloydminster Upgrader*
Lower Centre: *Delivering Husky branded products*

MIDSTREAM ASSETS

CREATING SYNERGIES IN THE VALUE CHAIN



During 2004, Midstream continued with several strategic initiatives. We grew our third party terminal facilities and service and also increased our shipping and distribution capabilities for heavy oil production. In preparation for developing our Sunrise Oil Sands Project, Husky increased its ownership in the Steepbank natural gas pipeline to 75.5 percent, and assumed operational responsibility. – D.R. (Don) Ingram, Senior Vice President, Midstream and Refined Products

Husky's midstream operations add value by minimizing cash flow volatility. Our midstream assets are primarily based in Western Canada and connect with key North American transportation systems. They include our heavy oil upgrader, pipelines, commodity marketing, electricity generation, crude oil and natural gas storage, and processing facilities.

LLOYDMINSTER UPGRADER

Husky's upgrader at Lloydminster, Saskatchewan, processes heavy oil feedstock into premium quality synthetic crude oil, which is sold to refiners in Eastern Canada and the United States. A debottlenecking project is under way to increase throughput capacity to 82,000 barrels of heavy oil and diluent per day.

FACILITIES AND NEW VENTURES

Husky owns and operates a 2,050-kilometre pipeline system that transports heavy oil production from the Lloydminster and Cold Lake areas to our terminal, upgrading and refining facilities in Lloydminster. Heavy oil and synthetic crude oil are also transported to Husky's terminal at Hardisty, Alberta, which connects with major export pipeline systems.

Husky has developed facilities at our Hardisty terminal to handle and blend one of the largest heavy oil crude streams in North America. Terminalling the new blend, known as Western Canada Select, commenced in December 2004 and increases Husky's presence in the North American crude oil market.

COMMODITY MARKETING

Commodity Marketing captures that portion of the value chain between the well head and the end-user. Husky aggregates, supplies, transports and stores proprietary and third-party crude oil, natural gas, natural gas liquids, sulphur and petroleum coke. During 2004, commodity volumes marketed exceeded 900,000 barrels of oil equivalent per day.

REFINED PRODUCTS
THROUGHPUT
PER OUTLET

OUTLOOK

- Increase throughput per location
- Maximize revenues per customer
- Commission the Lloydminster ethanol plant in early 2006
- Upgrade the Prince George refinery to produce low sulphur gasoline and diesel fuels
- Expand asphalt sales

- Emulsion Plants/Asphalt Terminals: 8
- Prince George Refinery: 10,000 bbls/day
- Lloydminster Asphalt Refinery: 25,000 bbls/day
- Minnedosa Ethanol Plant: 10 million litres/year

Total outlets: 531

Left: *Husky is a major supplier of paving asphalt*
Lower Left and Centre: *Husky's asphalt refinery and terminal in Lloydminster, Alberta*
Lower Right: *John C.S. Lau, Saskatchewan Premier Lorne Calvert and Senator Tommy Banks inaugurate construction for the Lloydminster ethanol plant*

REFINED PRODUCTS

REFINED PRODUCTS

MEETING NEW MARKETS

Refined Products is proceeding with our Clean Fuels Project to produce low sulphur fuels at Husky's Prince George Refinery, and construction of a world-scale plant in Lloydminster to produce ethanol for blending into our "Mother Nature's Fuel." Both initiatives will help to reduce greenhouse gas emissions from motor vehicles. We are continuing the rollout of our "Husky Market" concept and rationalization of our light oil business to emphasize growth in outlet throughput and lower operating costs. – D.R. (Don) Ingram, Senior Vice President, Midstream and Refined Products

RETAIL NETWORK

Over 500 retail outlets, travel centres and bulk distributors market Husky and Mohawk-branded fuels from Vancouver Island to Ontario. Husky's strategy to establish a niche in specialized markets continues to be on target. During 2004, average throughput per location was 4.3 million litres or eight percent higher than 2003. Throughput per location has increased 42 percent over the past five years.

Ancillary income from sales other than fuel was a record $30 million or almost seven percent greater than 2003. Our investment in technology and location upgrades is paying off with income from sales, other than fuel, increasing 15 percent in the past two years.

PRINCE GEORGE LIGHT OIL REFINERY

The Prince George Refinery produces unleaded gasoline, seasonal diesel fuels, butane and propane mix, and heavy fuel oil. In 2004, Husky initiated our Clean Fuels Project, a refinery expansion and upgrade to produce low sulphur gasoline and diesel fuels to meet the Government of Canada's new fuel specifications. Refinery throughput will increase to 12,000 barrels per day when the project is completed in 2006.

ETHANOL PRODUCTION

Husky is targeting to become the largest ethanol producer in Western Canada. Currently we produce 10 million litres per year at our plant in Minnedosa, Manitoba. In 2004, we began construction of a 130-million litre per year ethanol plant on the site of our heavy oil upgrader at Lloydminster, Saskatchewan. When it becomes operational in early 2006, the plant will produce ethanol from grain purchased from local producers meeting the need for environmentally friendly fuels and helping encourage rural development.

ASPHALT REFINING AND MARKETING

Husky's refinery at Lloydminster, Alberta produces asphalt products used in road construction and maintenance, and building products, as well as locomotive blendstock and specialty oil field products. In 2004, we set a new asphalt sales record of 22,800 barrels per day.

TOTAL HUSKY SULPHUR DIOXIDE (SO_2) EMISSIONS

OUTLOOK

- Continue to maintain or exceed established health, safety and environmental standards
- Improve the safety of Husky's work sites by hiring contractors who have demonstrated best safety practices and environmental awareness

Husky was honoured to receive:

- Recognition as one of Canada's Top 100 Employers for the fifth consecutive year
- Calgary Chamber of Commerce Salute to Excellence Award
- Ducks Unlimited Gold Legacy Sponsor Award

Left: *Safety of our workforce is key to Husky*
Lower Left: *John C.S. Lau receiving Ducks Unlimited Gold Legacy Award*
Lower Centre: *Husky is a proud supporter of the Husky Endangered Species Reintroduction Research Program at the Calgary Zoo*
Lower Right: *Husky strives to minimize our footprint where we operate*

OUR CORPORATE MISSION

GROWING IN A SOCIALLY RESPONSIBLE MANNER

Safety, concern for the environment, and participation in the community are not treated as side issues at Husky. They are core tenets of how we do business. – Wendell Carroll, Vice President, Corporate Administration

REGULATORY COMPLIANCE

The changing regulatory regime continues to provide challenges. Husky emphasizes responsibility for protecting the health and safety of our workforce and the public with each of our employees, from the executive level to the frontline worker, including contractors. To ensure that we meet or exceed our responsibilities our health, safety and environmental systems are constantly updated. Husky is continually improving its policies and practices to comply with and anticipate regulatory changes.

COMMUNICATIONS AND PUBLIC CONSULTATION

A large part of Husky's success is due to balancing the interests of multiple stakeholders and identifying enduring solutions that benefit all. Our proactive approach in meeting stakeholders in a variety of forums has ensured public support for the construction of our ethanol plant in Lloydminster and commercial development of our Tucker Oil Sands Project.

ENVIRONMENTAL STEWARDSHIP

Husky strives to minimize our footprint in those areas where we operate. At our Tucker Oil Sands Project, we are using a limited number of well sites to reduce surface disturbance. At our Moose Mountain development we have minimized the impact of our operations in consultation with our partners and community groups. We have also implemented a number of significant carbon dioxide reduction measures at our processing facilities.

Husky is an industry leader in environmental stewardship and supports the Husky Endangered Species Reintroduction Research Program at the Calgary Zoo and Ducks Unlimited Canada.

TRAINING AND AWARENESS

There has been an increase in contractor lost-time accidents due to higher activity levels, and service companies providing a largely inexperienced workforce. Husky is working with our contractors, industry members and regulators to ensure that our industry provides workers with improved training leading to a safer workplace.

The diminishing pool of qualified potential employees will also impact Husky as we commission some of our major projects. The Company is working with interested parties on a process for recognizing educational and professional qualifications from foreign institutions.

OUTLOOK

Husky is committed to its community investment program and will continue to seek out initiatives that maximize the value of its contributions and provide long-term benefits.

- Education/Youth **78%**
- Civic/Community **9%**
- Health & Welfare **6%**
- Aboriginal **4%**
- Environmental **2%**
- Arts & Culture **1%**

Husky was honoured to receive:

- Calgary Board of Education Lighthouse Award
- Canadian Breast Cancer Foundation Volunteer Business/Corporation Award

Husky has been recognized by Alberta's Promise for its initiatives in investing in Alberta's children and youth.

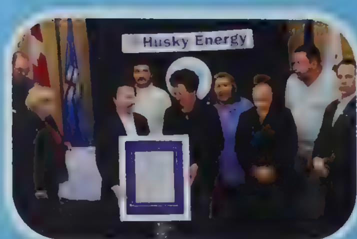
Alberta's Promise
A Partnership with Children and Youth
www.albertaspromise.org

Left: *University of Ottawa boreal forest*

Lower Left: *Husky renewed its commitment to the Chair in Bituminous Materials at the University of Calgary*

Lower Centre: *Husky values the culture and heritage of Aboriginal communities*

Lower Right: *Husky signed its eighth MOU with Cold Lake First Nation*



HUSKY AND OUR COMMUNITIES

HUSKY'S COMMITMENT

Husky is committed to conducting itself in a socially responsible manner in the communities in which it operates. This commitment extends directly from our senior management to all employees. In fulfilling this responsibility Husky focuses on three areas: the advancement of education; community donations; and Aboriginal affairs. – *J.C.S. (John) Lau, President & Chief Executive Officer*

EDUCATION

Husky has undertaken educational initiatives at several Canadian secondary and post-secondary institutions. During 2004, we established a $3-million endowment fund to support asphalt research and learning at the University of Calgary; contributed $125,000 to Lakeland College in Lloydminster; and provided $500,000 for the development of a boreal forest ecosystem open classroom at the University of Ottawa.

COMMUNITY DONATIONS

Husky's Community Donations Program reflects our belief that companies and their employees should have an opportunity to contribute to their communities. During 2004, Husky contributed to a variety of charities ranging from the Lloydminster Multiplex to teaming up with employees and our partner school, Western Canada High School in Calgary, to collect 3,500 blankets for social service agencies in Calgary, Lloydminster and Prince George.

Under our annual Employee Charitable Donations Program, Husky matches employees' donations to selected charities. In 2004, Husky and its employees together donated approximately $600,000 to 41 charities. In addition, Husky and its employees donated over $250,000 to the Canadian Red Cross, UNICEF, CARE and Doctors Without Borders to assist victims of the Asian tsunami disaster.

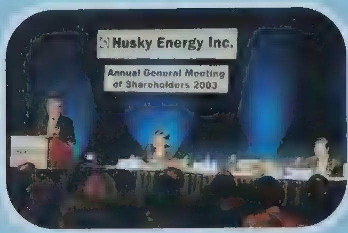
ABORIGINAL AFFAIRS

Husky values the culture and heritage of Canada's Aboriginal communities and the contributions they make to the development of our nation. To ensure that they can share in the benefits of this development we have signed memorandums of understanding (MOUs) with eight First Nations, which set out general principles for participation through business opportunities, employment, education and training.

We have also initiated programs to assist the 16 First Nations communities where we have operations, including the sponsorship of bursaries and the hiring of Aboriginal graduates.

HUSKY ENERGY INC. BOARD OF DIRECTORS

CORPORATE GOVERNANCE



Our Board of Directors is principally responsible for the Company's corporate governance practices. The Board of Directors has delegated to the Corporate Governance Committee some of the responsibilities for monitoring and enhancing the Company's governance practices. As part of the Board's commitment to good corporate governance, the Board reviewed and revised its charter and the charters of the committees of the Board in 2004 to better reflect the continuing evolution of corporate governance practices.

The Management Information Circular issued in connection with the April 21, 2005 Annual Meeting describes the Company's corporate governance practices.

The primary duties and responsibilities of the Board of Directors are to:

- approve, monitor and provide guidance on the strategic planning process. The President & CEO and senior management team have direct responsibility for the ongoing strategic planning process and the establishment of long-term goals for the Company, which are reviewed and approved not less than annually, by the Board of Directors
- identify the principal risks of the Company's business and take reasonable steps to ensure the implementation of appropriate systems to manage and monitor these risks
- delegate to the President & CEO the authority to manage and supervise the business of the Company, including the making of all decisions regarding the Company's operations that are not specifically reserved to the Board of Directors under the terms of that delegation of authority. The Board also determines what, if any, executive limitations may be required in the exercise of the authority delegated to management, and in this regard approves operational policies within which management will operate
- approve the Company's strategic plans, annual budget and financial plans
- oversee the integrity of the Company's internal control and management systems
- oversee effective communications with shareholders

COMMITTEES OF THE BOARD OF DIRECTORS

The Board has delegated certain of its responsibilities to four committees, each of which has specific roles and responsibilities as defined by the Board of Directors. All of the members of each committee are non-management directors.

AUDIT COMMITTEE

R.D. Fullerton (Chair); M.J.G. Glynn; T.C.Y. Hui; and W.E. Shaw

The Audit Committee is responsible for review and approval of the quarterly financial statements, management's discussion and analysis, all press releases containing financial disclosure, and the Company's oil and gas reserves reporting. The committee recommends to the Board the appointment and remuneration of the external auditors. The external auditors report directly to the committee. All non-audit work performed by the external auditors is to be approved by the committee. The committee also has oversight responsibility for the internal control systems that management has established.

COMPENSATION COMMITTEE

C.K.N. Fok (Chair); H. Kluge; E.L. Kwok; and F.J. Sixt

The Compensation Committee determines the total compensation and benefits of the President & CEO. On recommendation of the President & CEO, the Compensation Committee determines the general compensation programs for the Company and the compensation and benefit levels for the other senior officers. The committee's mandate is to ensure the overall compensation programs are designed to maintain the Company's desired competitive positioning in the oil and gas industry.

CORPORATE GOVERNANCE COMMITTEE

H. Kluge (Chair); E.L. Kwok; and W.E. Shaw

The Corporate Governance Committee is responsible for reviewing the effectiveness of the corporate governance practices of the Company, periodically reviewing the composition of the Board and its committees and their respective terms of reference. In conjunction with the Co-Chairs, the committee develops the annual performance objectives for the President & CEO. The committee is also responsible for ensuring appropriate procedures are in place so that the Board can function independently of management.

HEALTH, SAFETY AND ENVIRONMENT COMMITTEE

H. Kluge (Chair); B.D. Kinney; and S.T.L. Kwok

The Health, Safety and Environment Committee is responsible for reviewing and recommending for approval by the Board of Directors updates to the health, safety and environmental policy, the development with management and achievement of specific environmental objectives and targets, and for monitoring compliance with the Company's environmental policies.

HUSKY ENERGY INC. 2004

MANAGEMENT'S DISCUSSION AND ANALYSIS

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MANAGEMENT'S DISCUSSION AND ANALYSIS

February 16, 2005

Management's Discussion and Analysis is management's explanation of Husky's financial performance for the period covered by the financial statements along with an analysis of the Company's financial position and prospects. It should be read in conjunction with the Consolidated Financial Statements and notes thereto and the Statement of Reserves Data and Other Information in the Company's Annual Information Form. The Consolidated Financial Statements and all financial information included and incorporated by reference in this Annual Report have been prepared in accordance with accounting principles generally accepted in Canada. The effect of significant differences between Canadian and United States accounting principles is disclosed in Note 20 of the Consolidated Financial Statements. The following discussion and analysis refers primarily to 2004 as compared with 2003, unless otherwise indicated. Refer to the section "Results of Operations for 2003 Compared with 2002" for an abridged discussion. All dollar amounts are in millions of Canadian dollars, unless otherwise indicated. Unless otherwise indicated, all production volumes quoted are gross, which represent the Company's working interest share before royalties. Prices quoted include or exclude the effect of hedging as indicated. Crude oil has been classified as the following: light crude oil has an API gravity of 30 degrees or more; medium crude oil has an API gravity of 21 degrees or more and less than 30 degrees; heavy crude oil has an API gravity of less than 21 degrees.

Management's Discussion and Analysis contains the term "cash flow from operations", which should not be considered an alternative to, or more meaningful than "cash flow from operating activities", as determined in accordance with generally accepted accounting principles as an indicator of the Company's financial performance. The Company's determination of cash flow from operations may not be comparable to that reported by other companies. Cash flow from operations generated by each business segment represents a measurement of financial performance for which each reporting business segment is responsible. The items reported under the caption "Corporate and eliminations" are required to reconcile to the consolidated total and are not considered to be attributable to a business segment.

OVERVIEW

NET EARNINGS

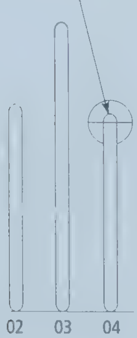
1,006

($ millions)

RETURN ON EQUITY

16.2

(percent)



SUMMARY OF RESULTS

Husky's operations are organized into three major business segments:

- The upstream segment includes the exploration for and the development and production of crude oil and natural gas in Western Canada, offshore the Canadian East Coast and offshore China and other international areas.
- The midstream segment is organized into two reportable business segments: heavy crude oil upgrading operations and infrastructure and commodity marketing operations. The infrastructure and commodity marketing segment comprises heavy crude oil pipeline and processing operations, natural gas storage, cogeneration operations, and marketing of crude oil, natural gas, natural gas liquids, sulphur and petroleum coke.
- The refined products segment includes the refining of crude oil and the marketing of refined petroleum products including asphalt products.

Selected Annual Information

Year ended December 31 *($ millions, except where indicated)*	*2004*	*% Change*	*2003 (1)*	*% Change*	*2002 (1)*
Sales and operating revenues, net of royalties	$ 8,440	10	$ 7,658	20	$ 6,384
Segmented earnings					
Upstream	$ 713	(33)	$ 1,067	53	$ 699
Midstream	240	30	185	15	161
Refined Products	41	28	32	(3)	33
Corporate and eliminations	12	(76)	50	163	(79)
Net earnings	$ 1,006	(25)	$ 1,334	64	$ 814
Per share – Basic	$ 2.37	(27)	$ 3.26	71	$ 1.91
– Diluted	$ 2.36	(27)	$ 3.25	71	$ 1.90
Dividends declared per common share	$ 0.46	21	$ 0.38	6	$ 0.36
Special dividend per common share	$ 0.54	(46)	$ 1.00	–	$ –
Total assets	$ 13,238	11	$ 11,946	12	$ 10,633
Total long-term debt and capital securities	$ 2,047	18	$ 1,730	(25)	$ 2,319
Return on equity *(percent)*	16.2		24.1		16.9
Return on average capital employed *(percent)*	12.8		18.1		12.3

(1) 2003 and 2002 amounts as restated. Refer to Note 3 to the Consolidated Financial Statements.

BUSINESS ENVIRONMENT

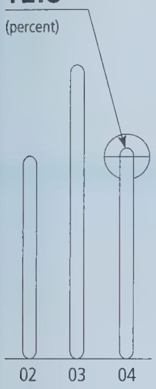
Husky's financial results are significantly influenced by its business environment. Risks include, but are not limited to:

- crude oil and natural gas prices
- the price differential and demand related to various crude oil qualities
- cost to find, develop, produce and deliver crude oil and natural gas
- availability of pipeline capacity
- the exchange rate between the Canadian and U.S. dollars
- refined products margins
- demand for Husky's pipeline capacity
- demand for refined petroleum products
- government regulations
- cost of capital

RETURN ON AVERAGE CAPITAL EMPLOYED

12.8

(percent)



Average Benchmark Prices and U.S. Exchange Rate

		[illegible]	[illegible]	[illegible]
WTI crude oil [1]	*(U.S. $/bbl)*	**$ 41.40**	$ 31.04	$ 26.08
Canadian par light crude 0.3% sulphur	*($/bbl)*	**$ 52.91**	$ 43.56	$ 40.28
Lloyd @ Lloydminster heavy crude	*($/bbl)*	**$ 28.75**	$ 26.44	$ 26.71
NYMEX natural gas [1]	*(U.S. $/mmbtu)*	**$ 6.14**	$ 5.39	$ 3.25
NIT natural gas	*($/GJ)*	**$ 6.44**	$ 6.35	$ 3.86
WTI/Lloyd crude blend differential	*(U.S. $/bbl)*	**$ 13.65**	$ 8.55	$ 6.47
U.S./Canadian dollar exchange rate	*(U.S. $)*	**$ 0.769**	$ 0.716	$ 0.637

(1) Prices quoted are near-month contract prices for settlement during the next month.

Commodity Price Risk

Our earnings depend largely on the profitability of our upstream business segment, which is significantly affected by fluctuations in oil and gas prices. Commodity prices have been, and are expected to continue to be, volatile due to a number of factors beyond our control. Refer to the section "Financial and Derivative Instruments" for a discussion of our use of hedging contracts.

Crude Oil

The prices received for our crude oil and NGL are related to the price of crude oil in world markets. These prices are further affected by the use of hedging contracts, which provide for payments or receipts depending on whether the underlying commodity price is higher or lower than an agreed upon strike price. Prices for heavy crude oil and other lesser quality crudes trade at a discount or differential to light crude oil.

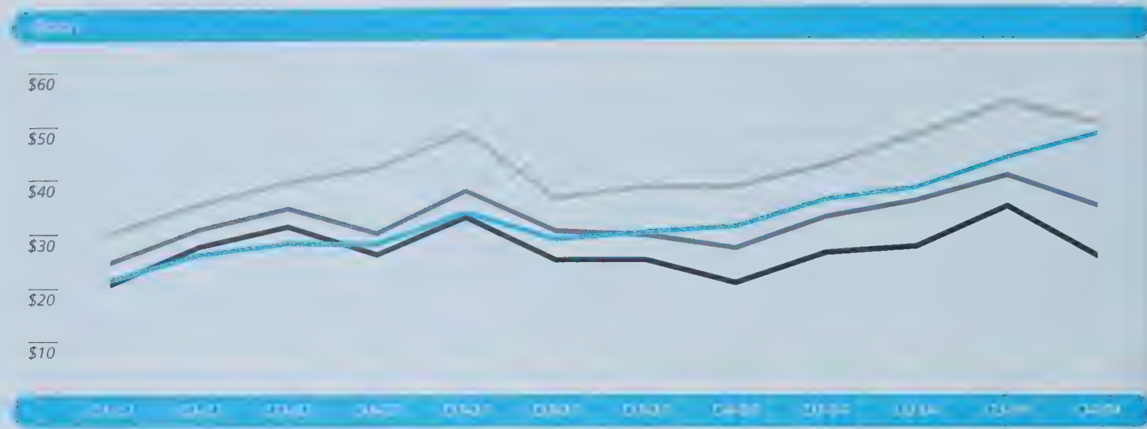
Benchmark crude oil prices averaged higher in 2004 compared with 2003. The price for West Texas Intermediate ("WTI") crude oil averaged U.S. $34.22/bbl in January 2004 and fluctuated between monthly averages of U.S. $34.50/bbl and U.S. $53.09/bbl during the remainder of the year.

During 2004 record high world crude oil prices resulted from a number of factors. The year started off with low crude oil inventories in the United States followed by uncertainty as to Iraqi production; damaged infrastructure caused by hurricanes Charley, Frances and Ivan; higher demand for crude oil spurred by increasing demand from China and India; and continued instability in Venezuela, Nigeria and Russia.

Numerous factors could affect world crude oil prices in 2005. We expect prices to fluctuate with weather forecasts, announcements by the Organization of Petroleum Exporting Countries' oil ministers or any perceived threat of supply disruptions. However, in the longer term, supply and demand will be the key in determining price factors with an emphasis on demand.

During 2004 heavy crude oil differentials averaged U.S. $13.65/bbl for WTI/Lloyd crude blend compared with U.S. $8.55/bbl during 2003. However, in December 2004 the average price for Lloydminster crude oil with an API gravity of 12 to 14 degrees averaged $12.27/bbl while light crude oil averaged above the $50.00/bbl level. The wider differential tends to reduce Husky's overall financial results as our crude oil production is weighted toward heavier gravity crudes. In periods of wider differentials, our heavy oil upgrader partially offsets the impact of the lower heavy oil value compared with light oil.

WTI and Husky Average Crude Oil Prices



West Texas Intermediate ("WTI") *(U.S. $)*	$21.64	$26.25	$28.27	$28.15	$33.86	$28.91	$30.20	$31.18	$35.15	$38.32	$43.88	$48.28
Husky average light crude oil price *(Cdn $)*	$30.35	$35.56	$39.64	$42.23	$48.58	$36.45	$38.49	$38.55	$42.50	$47.99	$53.94	$50.29
Husky average medium crude oil price *(Cdn $)*	$24.84	$30.90	$34.76	$30.12	$37.86	$30.48	$29.68	$27.25	$32.97	$35.98	$40.59	$35.06
Husky average heavy crude oil price *(Cdn $)*	$20.95	$27.75	$31.41	$26.20	$33.02	$25.13	$25.13	$20.84	$26.38	$27.54	$34.92	$25.81

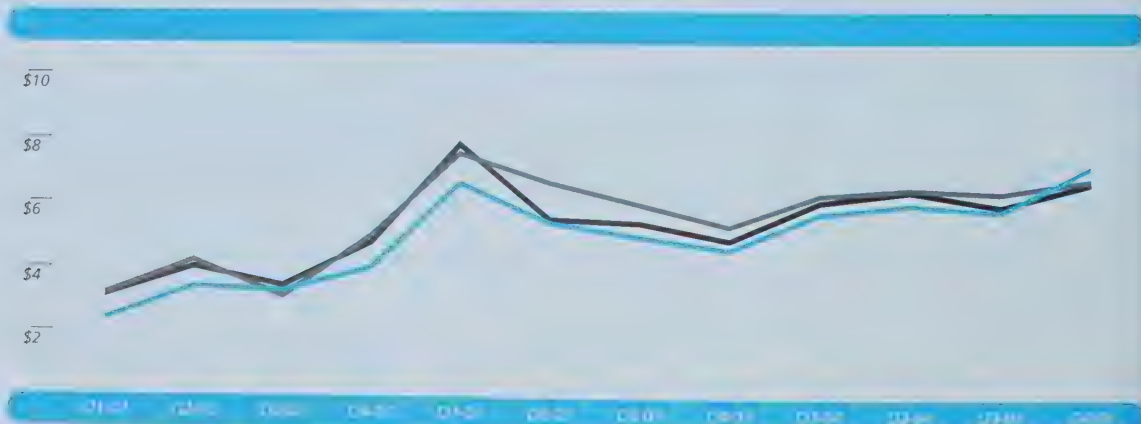
Natural Gas

The price of natural gas in North America is affected by regional supply and demand factors, particularly those affecting the United States such as weather conditions, pipeline delivery capacity, production disruptions, the availability of alternative sources of less costly energy supply, inventory levels and general industry activity levels. Periodic imbalances between supply and demand for natural gas are common and result in volatile pricing.

Throughout 2004 natural gas prices on the New York Mercantile Exchange ("NYMEX") fluctuated just below the U.S. $6.00/mmbtu level ending the year on the U.S. $6.00/mmbtu level and fluctuating with weather conditions.

The prices received for Husky's natural gas are based either on fixed price contracts, spot prices, NYMEX or other regional market prices. The prices received are further affected by the use of hedging contracts, which provide for payments or receipts depending on whether the underlying commodity price is higher or lower than an agreed upon strike price.

NYMEX Natural Gas, NIT Natural Gas and Husky Average Natural Gas Prices



NYMEX natural gas *(U.S. $/mmbtu)*	$2.38	$3.37	$3.26	$3.99	$6.60	$5.39	$4.97	$4.58	$5.69	$5.97	$5.76	$7.11
NIT natural gas *(Cdn $/GJ)*	$3.17	$4.19	$3.08	$4.98	$7.51	$6.63	$5.97	$5.30	$6.26	$6.45	$6.32	$6.72
Husky average natural gas price *(Cdn $/mcf)*	$3.10	$3.98	$3.42	$4.76	$7.80	$5.50	$5.40	$4.87	$6.05	$6.38	$5.92	$6.64

Upgrading Differential

The profitability of Husky's heavy oil upgrading operations is dependent upon the amount by which revenues from the synthetic crude oil produced exceed the costs of the heavy oil feedstock plus the related operating costs. An increase in the price of blended heavy crude oil feedstock that is not accompanied by an equivalent increase in the sales price of synthetic crude oil would reduce the profitability of our upgrading operations. We have significant crude oil production that trades at a discount to light crude oil, and any negative effect of a narrower differential on upgrading operations would be more than offset by a positive effect on revenues in the upstream segment from heavy oil production.

Refined Products Margins

The margins realized by Husky for refined products are affected by crude oil price fluctuations, which affect refinery feedstock costs, and third-party light oil refined product purchases. Husky's ability to maintain refined products margins in an environment of higher feedstock costs is contingent upon the ability to pass on higher costs to our customers.

Integration

Husky's production of light, medium and heavy crude oil and natural gas and the efficient operation of our upgrader, refineries and other infrastructure provide opportunities to take advantage of any fluctuation in commodity prices while assisting in managing commodity price volatility. Although we are predominantly an oil and gas producer, the nature of our integrated organization is such that the upstream business segment's output provides input to the midstream and refined products segments.

Foreign Exchange Risk

Our results are affected by the exchange rate between the Canadian and U.S. dollars. The majority of our revenues are received in U.S. dollars or from the sale of oil and gas commodities that receive prices determined by reference to U.S. benchmark prices. The majority of Husky's expenditures are in Canadian dollars. An increase in the value of the Canadian dollar relative to the U.S. dollar will decrease the revenues received from the sale of oil and gas commodities and correspondingly a decrease in the value of the Canadian dollar relative to the U.S. dollar will increase the revenues received from the sale of oil and gas commodities. In addition, a change in the value of the Canadian dollar against the U.S. dollar will result in an increase or decrease in Husky's U.S. dollar denominated debt, as expressed in Canadian dollars, as well as in the related interest expense. At December 31, 2004, 80 percent or $1.7 billion of our long-term debt and capital securities were denominated in U.S. dollars. The Cdn/U.S. exchange rate at the end of 2004 was $1.20. The percentage of our long-term debt and capital securities exposed to the Cdn/U.S. exchange rate decreases to 61 percent when the cross currency swaps are included. Refer to the section "Financial and Derivative Instruments."

Interest Rates

Husky maintains a portion of its debt in floating rate facilities which are exposed to interest rate fluctuations. We will occasionally fix our floating rate debt or create a variable rate for our fixed rate debt using derivative financial instruments. Refer to the section "Financial and Derivative Instruments."

Environmental Regulations

Most aspects of Husky's business are subject to environmental laws and regulations. Similar to other companies in the oil and gas industry, we incur costs for preventive and corrective actions. Changes to regulations could have an adverse effect on our results of operations and financial condition.

International Operations

In addition to commodity price risk, Husky's international upstream operations may be affected by a variety of factors including political and economic developments, exchange controls, currency fluctuations, royalty and tax increases, import and export regulations and other foreign laws or policies affecting foreign trade or investment.

SENSITIVITY ANALYSIS

The following table is indicative of the relative effect on pre-tax cash flow and net earnings from changes in certain key variables in 2004. The analysis is based on business conditions and production volumes during 2004. Each separate item in the sensitivity analysis shows the effect of an increase in that variable only; all other variables are held constant. While these sensitivities are applicable for the period and magnitude of changes on which they are based, they may not be applicable in other periods, under other economic circumstances or greater magnitudes of change.

Sensitivity Analysis

Item	*Increase*	*Effect on Pre-tax Cash Flow*		*Effect on Net Earnings*	
		($ millions)	*($/share)* [4]	*($ millions)*	*($/share)* [4]
WTI benchmark crude oil price					
Excluding commodity hedges	U.S. $1.00/bbl	$ 87	$ 0.20	$ 59	$ 0.14
Including commodity hedges	U.S. $1.00/bbl	46	0.11	30	0.07
NYMEX benchmark natural gas price [1]					
Excluding commodity hedges	U.S. $0.20/mmbtu	38	0.09	25	0.06
Including commodity hedges	U.S. $0.20/mmbtu	36	0.09	23	0.06
Light/heavy crude oil differential [2]	Cdn $1.00/bbl	(30)	(0.07)	(20)	(0.05)
Light oil margins	Cdn $0.005/litre	15	0.04	10	0.02
Asphalt margins	Cdn $1.00/bbl	8	0.02	5	0.01
Exchange rate (U.S. $ per Cdn $) [3]					
Including commodity hedges	U.S. $0.01	(54)	(0.13)	(35)	(0.08)

(1) Includes decrease in earnings related to natural gas consumption.

(2) Includes impact of upstream and upgrading operations only.

(3) Assumes no foreign exchange gains or losses on U.S. dollar denominated long-term debt and other monetary items. The impact of the Canadian dollar strengthening by U.S. $0.01 would be an increase of $10 million in net earnings based on December 31, 2004 U.S. dollar denominated debt levels.

(4) Based on December 31, 2004 common shares outstanding of 423.7 million.

RESULTS OF OPERATIONS

DAILY PRODUCTION, BEFORE ROYALTIES – LIGHT CRUDE OIL & NGL

66.2

(mbbls/day)

DAILY PRODUCTION, BEFORE ROYALTIES – MEDIUM CRUDE OIL

35.0

(mbbls/day)

UPSTREAM

Upstream Earnings Summary [(1)]

Year ended December 31 ($ millions)	2004	2003	2002
Gross revenues	$ 4,392	$ 3,796	$ 3,120
Royalties	711	584	460
Hedging (gain) loss	561	26	(5)
Net revenues	3,120	3,186	2,665
Operating and administration expenses	967	873	743
Depletion, depreciation and amortization	1,077	918	822
Income taxes	363	328	401
Earnings	$ 713	$ 1,067	$ 699

(1) 2003 and 2002 amounts as restated. Refer to Note 3 to the Consolidated Financial Statements.

Upstream earnings in 2004 were $354 million lower than in 2003 primarily due to the following factors:

- hedging losses which were related primarily to 85 mbbls/day of crude oil production hedged at a strike price of U.S. $27.46 compared with 27.6 mbbls/day hedged at a strike price of U.S. $29.50 in 2003
- higher royalties resulting from higher commodity prices
- lower sales volume of light and medium crude oil
- unit operating costs were $0.40/boe higher in 2004 compared with 2003 as a result of:
  - – higher field facilities maintenance costs
  - – higher fuel costs
  - – higher transportation costs

  partially offset by:
  - – lower electrical power costs due to lower rates and initiatives that resulted in lower consumption
- unit depletion, depreciation and amortization expense ("DD&A") increased by $1.01/boe to $9.06/boe in 2004 compared with 2003 as a result of:
  - – higher maintenance capital requirements for properties in the Western Canada Sedimentary Basin, particularly for mature properties under secondary or tertiary enhanced recovery schemes and shallow natural gas operations
  - – offshore operations requiring substantial capital investments
  - – purchased proved oil and gas reserves in-place, whether as individual properties or through a corporate acquisition, cost more per boe of reserves added than our current DD&A per boe of $9.06/boe
- higher income taxes

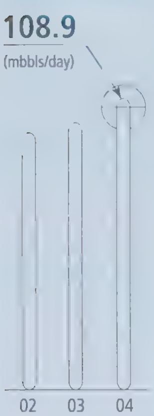
partially offset by:

- higher prices for crude oil and natural gas
- higher sales volume of heavy crude oil and natural gas

Income taxes with respect to our upstream business segment increased in 2004 to $363 million from $328 million in 2003 despite lower pre-tax earnings. In 2004 the indicative income tax rate was higher than in 2003 as a result of amendments to the Federal and Alberta income tax acts, the benefits from which were recorded in 2003. The 2003 amendment to the Income Tax Act reduced the income tax rate on resource income by seven percent, provides for the deduction from income of crown royalties and eliminates the resource allowance deduction. The amendment is being phased in over a five-year period. The total

benefit recorded in 2003 with respect to Bill C-48 was $141 million. In addition, a non-recurring upstream benefit totalling $18 million was recorded in 2003 pursuant to Bill 41, the Alberta Corporate Tax Amendment Act, 2003. Both benefits recorded in 2003 reduced our future income taxes related to upstream operations. In 2004, an upstream benefit of $36 million was recorded for changes in the Alberta corporate tax rate.

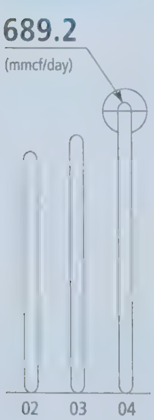
DAILY PRODUCTION, BEFORE ROYALTIES – HEAVY CRUDE OIL



Net Revenue Variance Analysis

[illegible]	Crude Oil & NGL	Natural Gas	Other	Total
Year ended December 31, 2002				
Net revenues	$ 1,987	$ 637	$ 41	$ 2,665
Price changes	85	450	–	535
Volume changes	59	58	–	117
Royalties	16	(140)	–	(124)
Hedging	(50)	19	–	(31)
Processing and sulphur	–	–	24	24
Year ended December 31, 2003				
Net revenues	2,097	1,024	65	3,186
Price changes	359	98	–	457
Volume changes	(36)	172	–	136
Royalties	(67)	(60)	–	(127)
Hedging	(514)	(21)	–	(535)
Processing and sulphur	–	–	3	3
Year ended December 31, 2004				
Net revenues	**$ 1,839**	**$ 1,213**	**$ 68**	**$ 3,120**

DAILY PRODUCTION, BEFORE ROYALTIES – NATURAL GAS



Daily Production, before Royalties

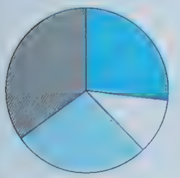
Year ended December 31		2004	2003	2002
Light crude oil & NGL	*(mbbls/day)*	**66.2**	71.6	65.4
Medium crude oil	*(mbbls/day)*	**35.0**	39.2	44.8
Heavy crude oil	*(mbbls/day)*	**108.9**	99.9	95.1
Total crude oil & NGL	*(mbbls/day)*	**210.1**	210.7	205.3
Natural gas	*(mmcf/day)*	**689.2**	610.6	569.2
Barrels of oil equivalent (6:1)	*(mboe/day)*	**325.0**	312.5	300.2

Average Sales Prices

[illegible]		2004	[illegible]	[illegible]
Crude oil	*($/bbl)*			
Light crude oil & NGL		**$ 48.34**	$ 39.53	$ 36.17
Medium crude oil		**36.13**	31.42	30.16
Heavy crude oil		**28.66**	25.87	26.60
Total average		**36.07**	31.54	30.43
Total average after hedging		**28.43**	30.93	30.50
Natural gas	*($/mcf)*			
Average		**$ 6.25**	$ 5.86	$ 3.83
Average after hedging		**6.24**	5.94	3.83

DAILY PRODUCTION, BEFORE ROYALTIES – TOTAL

2004 UPSTREAM REVENUE MIX



- Light Crude Oil & NGL 27%
- Medium Crude Oil 11%
- Heavy Crude Oil 27%
- Natural Gas 35%

Upstream Revenue Mix (1)

Year ended December 31	2004	2003	2002
Percentage of upstream sales revenues, after royalties			
Light crude oil & NGL	**27%**	29%	24%
Medium crude oil	**11%**	12%	25%
Heavy crude oil	**27%**	26%	25%
Natural gas	**35%**	33%	26%
Total	**100%**	100%	100%

Effective Royalty Rates (1)

[illegible]	[illegible]	[illegible]	[illegible]
Percentage of upstream sales revenues			
Light crude oil & NGL	**13%**	12%	13%
Medium crude oil	**18%**	17%	17%
Heavy crude oil	**12%**	11%	11%
Natural gas	**22%**	22%	18%
Total	**16%**	16%	15%

(1) Before commodity hedging.

Operating Netbacks

Western Canada

Light Crude Oil Netbacks (1)

Year ended December 31 (per boe)	[illegible]	[illegible]	[illegible]
Sales revenues before hedging	**$ 46.12**	$ 39.91	$ 33.66
Royalties	**7.76**	7.28	4.55
Operating costs	**8.94**	9.27	10.46
Netback	**$ 29.42**	$ 23.36	$ 18.65

Medium Crude Oil Netbacks (1)

Year ended December 31 (per boe)	2004	2003	2002
Sales revenues before hedging	**$ 36.20**	$ 31.57	$ 29.92
Royalties	**6.10**	5.28	5.59
Operating costs	**10.07**	9.53	7.19
Netback	**$ 20.03**	$ 16.76	$ 17.14

Heavy Crude Oil Netbacks (1)

Year ended December 31 (per boe)	[illegible]	[illegible]	[illegible]
Sales revenues before hedging	**$ 28.73**	$ 25.98	$ 26.48
Royalties	**3.38**	2.76	3.45
Operating costs	**9.33**	9.09	7.18
Netback	**$ 16.02**	$ 14.13	$ 15.85

(1) Includes associated co-products converted to boe.

TOTAL WESTERN CANADA UPSTREAM NETBACKS

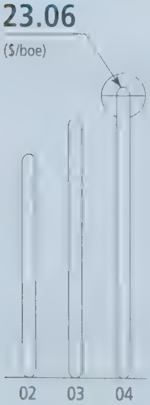
20.94

($/boe)

TOTAL UPSTREAM SEGMENT NETBACKS

23.06

($/boe)



Natural Gas Netbacks (2)

Year ended December 31 (per mcfge)	2004	2003	2002
Sales revenues before hedging	**$ 6.25**	$ 5.79	$ 3.97
Royalties	**1.44**	1.29	0.81
Operating costs	**0.89**	0.79	0.70
Netback	**$ 3.92**	$ 3.71	$ 2.46

Total Western Canada Upstream Netbacks (1)

Year ended December 31 (per boe)	2004	2003	2002
Sales revenues before hedging	**$ 35.01**	$ 31.58	$ 27.04
Royalties	**6.22**	5.48	4.46
Operating costs	**7.85**	7.56	6.54
Netback	**$ 20.94**	$ 18.54	$ 16.04

Terra Nova Crude Oil Netbacks

Year ended December 31 (per boe)	2004	2003	2002
Sales revenues before hedging	**$ 47.87**	$ 38.91	$ 35.47
Royalties	**1.80**	0.81	0.36
Operating costs	**3.28**	3.16	3.62
Netback	**$ 42.79**	$ 34.94	$ 31.49

Wenchang Crude Oil Netbacks

Year ended December 31 (per boe)	2004	2003	2002
Sales revenues before hedging	**$ 47.66**	$ 41.45	$ 44.36
Royalties	**4.91**	3.80	2.65
Operating costs	**2.16**	1.94	2.15
Netback	**$ 40.59**	$ 35.71	$ 39.56

Total Upstream Segment Netbacks (1)

Year ended December 31 (per boe)	2004	2003	2002
Sales revenues before hedging	**$ 36.34**	$ 32.69	$ 28.12
Royalties	**5.96**	5.11	4.20
Operating costs	**7.32**	6.92	6.24
Netback	**$ 23.06**	$ 20.66	$ 17.68

(1) Includes associated co-products converted to boe.
(2) Includes associated co-products converted to mcfge.

Upstream Plans and Outlook

In 2004, 90 percent of our production of oil and gas was from the Western Canada Sedimentary Basin, up from 87 percent in 2003. Our total production in 2004 was up four percent over 2003 primarily due to higher production from our properties in Western Canada, in particular natural gas and heavy oil. Although the oil production from the White Rose oil field offshore Newfoundland and Labrador in 2006 will shift this balance significantly, Western Canada will remain our key production base and therefore our key exploration and development focus.

Western Canada Sedimentary Basin

Our exploration programs in the Western Canada Sedimentary Basin will remain focused in the foothills and Deep Basin area of Alberta and northeastern British Columbia. Recently we have directed some of our interest north of the 60th parallel to the central Mackenzie Valley in the Northwest Territories.

At our other oil and gas properties, we will continue our strategy of applying reservoir and production optimization through in-fill drilling, application of improved recovery schemes such as horizontal wells and chemical floods as well as traditional water flooding and emerging technologies, as they become available and commercially viable. We will also explore the limits of our reservoirs through step-out drilling programs and make use of opportunities such as property swaps, acquisitions and continue to expand the development potential of coal bed methane. Another common theme in our strategic plans involves utilizing new technology and implementation of improved practices to mitigate increasing costs.

Also in the Western Canada Sedimentary Basin but relatively new to our portfolio of opportunities, the Tucker and Sunrise Oil Sands Projects are on schedule. Tucker is expected to begin production in late 2006.

Western Canada Sedimentary Basin capital spending is projected to be $1.7 billion in 2005. Actual capital spending in 2004 was $1.5 billion.

Canada's East Coast

Our activities offshore Canada's East Coast began in the early 1980s and the results were first realized in 2002 with the development of the Terra Nova oil field (12.51 percent working interest). The White Rose oil field, in which we hold a 72.5 percent working interest, was sanctioned in 2002. White Rose is scheduled to produce first oil in late 2005 or early 2006.

We hold interests in 15 significant discovery license areas in the Jeanne d'Arc Basin and several exploration licenses, three of which were acquired in the fourth quarter of 2004. We will continue to pursue the potential of this area including its considerable natural gas potential.

East Coast capital spending is projected to be $556 million in 2005. Actual capital spending in 2004 was $519 million.

Offshore China

In the South China Sea we hold 40 percent of the Wenchang oil fields which commenced production in July 2002. We also hold production sharing contracts in five blocks in the South China Sea and one in the East China Sea. We expect to drill three exploration wells in 2005 in our exploration blocks in the South China Sea, contingent on rig availability.

Offshore China capital spending is projected to be $37 million in 2005. Actual capital spending in 2004 was $23 million.

Offshore Indonesia

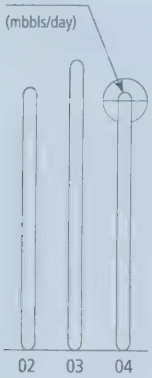
In the fourth quarter of 2004 we acquired our partner's interest in a production sharing contract ("PSC") in the Madura Strait providing us with a 100 percent interest. The PSC contains two natural gas and natural gas liquids discoveries. With only nine wells drilled in total on this 2,800 square kilometre block, we have identified several exploration opportunities.

Offshore Indonesia capital spending is projected to be $6 million in 2005.

UPGRADER THROUGHPUT

64.6

(mbbls/day)



MIDSTREAM

Upgrading Earnings Summary

Year ended December 31 ($ millions, except where indicated)		2004	2003	2002
Gross margin		$ 383	$ 313	$ 246
Operating costs		214	205	154
Other recoveries		(5)	(4)	(6)
Depreciation and amortization		19	20	18
Income taxes		43	21	26
Earnings		$ 112	$ 71	$ 54
Upgrader throughput (1)	*(mbbls/day)*	64.6	72.5	65.4
Synthetic crude oil sales	*(mbbls/day)*	53.7	63.6	59.3
Upgrading differential	*($/bbl)*	$ 17.79	$ 12.88	$ 10.81
Unit margin	*($/bbl)*	$ 19.48	$ 13.51	$ 11.05
Unit operating cost (2)	*($/bbl)*	$ 9.07	$ 7.77	$ 6.48

(1) Throughput includes diluent returned to the field.
(2) Based on throughput.

Upgrading earnings increased by $41 million in 2004 primarily due to:

- wider upgrading differential, which averaged $17.79/bbl in 2004 compared with $12.88/bbl in 2003

partially offset by:

- lower throughput and sales volume
- higher operating costs
- higher income taxes

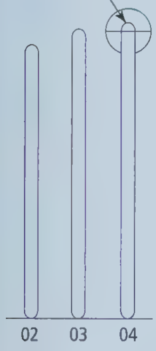
Upgrading Earnings Variance Analysis

[illegible]	
Year ended December 31, 2002	$ 54
Volume	18
Differential	49
Operating costs – energy related	(49)
Operating costs – non-energy related	(2)
Other	(2)
Depreciation and amortization	(2)
Income taxes	5
Year ended December 31, 2003	71
Volume	(48)
Differential	118
Operating costs – non-energy related	(9)
Other	1
Depreciation and amortization	1
Income taxes	(22)
Year ended December 31, 2004	**$ 112**

PIPELINE THROUGHPUT

492

(mbbls/day)



Infrastructure and Marketing Earnings Summary

Year ended December 31 ($ millions, except where indicated)		*2004*	*2003*	*2002*
Gross margin				
Pipeline		$ **84**	$ 66	$ 55
Other infrastructure and marketing		**136**	141	147
		220	207	202
Other expenses		**8**	8	10
Depreciation and amortization		**21**	21	20
Income taxes		**63**	64	65
Earnings		$ **128**	$ 114	$ 107
Aggregate pipeline throughput	*(mbbls/day)*	**492**	484	457

Infrastructure and marketing earnings increased by $14 million in 2004 primarily due to:

- higher heavy crude oil pipeline throughput and tariffs
- higher Lloyd blend marketing margins
- higher crude oil and NGL trading

partially offset by:

- lower natural gas commodity marketing margins
- lower cogeneration income

Midstream Plans and Outlook

Upgrading

The Husky Lloydminster Upgrader is a heavy oil upgrading facility capable of a feedstock charge of 77 mbbls/day of blended heavy crude oil feedstock and production of approximately 65 mbbls/day of Husky Synthetic Blend after diluent is returned to the field. The facility is located in the midst of the Lloydminster heavy oil producing area and is integrated with our pipelines, storage and the Husky Lloydminster asphalt refinery. The upgrading facility is currently undergoing a debottlenecking program, which when completed in 2006 will have increased processing capacity to 82 mbbls/day of blended feedstock and improved operating efficiency and reliability.

Upgrader capital spending is projected to be $87 million in 2005. Actual upgrader capital spending in 2004 was $62 million.

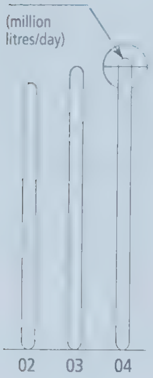
Pipelines

Our heavy oil pipeline systems total in excess of 2,050 kilometres throughout the Lloydminster heavy oil producing area from Cold Lake through Lloydminster to the Hardisty Alberta terminal. The pipeline systems are capable of transporting in excess of 575 mbbls/day of blended heavy crude oil. With the volume of heavy crudes and bitumen forecast to grow in the near term we will focus our pipeline investments where we hold a competitive advantage in preparation for increased throughput.

Pipeline capital spending is projected to be $44 million in 2005. Actual capital spending in 2004 was $31 million.

LIGHT OIL PRODUCTS SALES VOLUME

8.4



LLOYDMINSTER REFINERY THROUGHPUT

25.3

REFINED PRODUCTS

Refined Products Earnings Summary[1]

Year ended December 31 ($ millions, except where indicated)		*2004*	*2003*	*2002*
Gross margin				
Fuel sales		**$ 93**	$ 71	$ 81
Ancillary sales		**30**	28	26
Asphalt sales		**51**	51	45
		174	150	152
Operating and other expenses		**71**	74	66
Depreciation and amortization		**38**	26	31
Income taxes		**24**	18	22
Earnings		**$ 41**	$ 32	$ 33
Number of fuel outlets		**531**	552	571
Refined products sales volume				
Light oil products	*(million litres/day)*	**8.4**	8.2	7.7
Light oil products per outlet	*(thousand litres/day)*	**11.7**	10.8	10.0
Asphalt products	*(mbbls/day)*	**22.8**	22.0	20.8
Refinery throughput				
Prince George refinery	*(mbbls/day)*	**9.8**	10.3	10.1
Lloydminster refinery	*(mbbls/day)*	**25.3**	25.7	22.0

(1) 2003 and 2002 amounts as restated. Refer to Note 3 to the Consolidated Financial Statements.

Refined products earnings increased by $9 million in 2004 primarily due to:

- higher light oil product margins
- higher restaurant and convenience store income

partially offset by:

- higher depreciation and amortization
- higher income taxes

Refined Products Plans and Outlook

Our refined products business is composed of a small full slate refinery at Prince George in north central British Columbia, an asphalt refinery in Lloydminster, Alberta, an ethanol plant at Minnedosa, Manitoba and, at December 31, 2004, 507 retail petroleum outlets and 24 wholesale outlets. Also, in association with our petroleum outlets we had 45 branded restaurants and 484 convenience stores. We will continue our retail outlet upgrade program to respond to consumer expectations. In addition, we are beginning construction of a new ethanol plant located in Lloydminster, Saskatchewan to capture benefits from government mandated demand for ethanol blended motor fuels.

We are currently in the process of upgrading the Prince George refinery to meet new government specifications for sulphur content in fuel and to increase throughput capacity from 10,000 bbls/day to approximately 12,000 bbls/day.

In 2005, our asphalt products strategic focus will be directed toward refinery improvements including debottlenecking and various cost efficiency initiatives and terminal improvements.

Refined products capital spending is projected to be $240 million in 2005. Actual capital spending in 2004 was $106 million.

CORPORATE

Corporate Earnings Summary [1]

Year ended December 31 ($ millions)	2004	2003	2002
Intersegment eliminations – net	**$ 14**	$ (14)	$ 19
Administration expenses	**27**	22	10
Stock-based compensation	**67**	–	–
Accretion	**2**	–	1
Other – net	**8**	3	5
Depreciation and amortization	**24**	36	17
Interest on debt	**109**	131	131
Interest capitalized	**(75)**	(52)	(26)
Interest income	**(1)**	(6)	(1)
Foreign exchange	**(99)**	(215)	13
Income taxes	**(88)**	45	(90)
Earnings (loss)	**$ 12**	$ 50	$ (79)

(1) 2003 and 2002 amounts as restated. Refer to Note 3 to the Consolidated Financial Statements.

Foreign Exchange Summary

Year ended December 31 ($ millions)	2004	2003	2002
(Gain) loss on translation of U.S. dollar denominated long-term debt			
Realized	**$ (10)**	$ 11	$ 11
Unrealized	**(119)**	(326)	(11)
	(129)	(315)	–
Cross currency swaps			
Realized	**–**	32	–
Unrealized	**27**	41	–
	27	73	–
Other losses	**3**	27	13
	$ (99)	$ (215)	$ 13
U.S./Canadian dollar exchange rates:			
At beginning of year	**U.S. $0.774**	U.S. $0.633	U.S. $0.628
At end of year	**U.S. $0.831**	U.S. $0.774	U.S. $0.633

Corporate earnings were lower in 2004 compared with 2003 primarily due to:

- lower foreign exchange gains
- stock-based compensation first recorded in June 2004 (refer to the section "New Accounting Standards")
- higher intersegment profit eliminated
- higher administration expenses

partially offset by:

- lower depreciation and amortization
- lower interest expense resulting from lower rates
- higher capitalized interest resulting from a higher capital base for the White Rose Project

Consolidated Income Taxes

Consolidated income taxes decreased in 2004 to $405 million from $476 million in 2003 as a result of lower pre-tax earnings and non-recurring tax benefits. In 2004 the indicative income tax rate was higher than in the previous year as a result of the 2003 amendments to the Federal and Alberta income tax acts. On May 11, 2004, Bill 27-Alberta Corporate Tax Amendment Act, 2004 received royal assent in the Alberta Legislative Assembly. As a result, a non-recurring benefit of $40 million was recorded in 2004. During 2003, an amendment to the Income Tax Act reduced the income tax rate on resource income by seven percent, provides for the deduction from income of crown royalties and eliminates the resource allowance deduction. The amendment is being phased in over a five-year period. The total benefit recorded in 2003 was $141 million. In addition, in 2003 a non-recurring benefit totalling $20 million was recorded pursuant to Bill 41, the Alberta Corporate Tax Amendment Act, 2003. All benefits reduced future income taxes.

In 2004 current income taxes totalled $302 million and comprised $85 million in respect of the Wenchang oil field operation, $20 million of capital taxes and $197 million of Canadian income tax.

The following table shows the effect of non-recurring tax benefits for the periods noted:

($ millions)	*2004*	*2003*
Income taxes before tax amendments	$ **445**	$ 637
Canadian federal and provincial tax amendments	**40**	161
Income taxes as reported	$ **405**	$ 476

Husky's Canadian Tax Pools

Year ended December 31 ($ millions)	*2004*	*2003*
Canadian exploration expense	$ **–**	$ 42
Canadian development expense	**1,616**	1,103
Canadian oil and gas property expense	**557**	814
Foreign exploration and development expense	**212**	142
Undepreciated capital costs	**3,269**	2,909
Other	**22**	22
	$ **5,676**	$ 5,032

CAPITAL RESOURCES

OPERATING ACTIVITIES

In 2004 cash generated by operating activities was $2,352 million, a decrease of $186 million from the $2,538 million recorded in 2003. The lower cash from operating activities in 2004 was primarily due to the negative impact of the hedging program, partially offset by higher commodity prices.

FINANCING ACTIVITIES

In 2004 cash provided by financing activities amounted to $149 million. The cash used was composed of the repayment of long-term debt of $1,937 million and a $22 million repayment of operating lines, payment of the return on capital securities of $26 million, dividends of $424 million, including a $0.54 per share special dividend and debt issue costs of $5 million. Cash provided by financing activities in 2004 comprised $2,200 million issuance of long-term debt, $18 million of proceeds from the exercise of stock options, proceeds from monetization of financial instruments totalling $8 million and a change of $337 million in non-cash working capital.

Husky's long-term debt balances were also reduced by $129 million during 2004 primarily as a result of the narrowing of the exchange rate between Canadian and U.S. currencies.

INVESTING ACTIVITIES

Cash used in investing activities amounted to $2,497 million in 2004, an increase of $456 million from the $2,041 million in 2003. Cash invested in 2004 was composed of capital expenditures of $2,349 million and the acquisition of Temple Exploration Inc. for $102 million, partially offset by $36 million of proceeds from asset sales. Change in non-cash working capital and other adjustments amounted to $82 million used in investing activities.

Upstream Capital Expenditures

Western Canada

During 2004, capital expenditures for exploration and development in Western Canada totalled $1,533 million compared with $1,195 million during 2003.

Total development capital spending in Western Canada during 2004 amounted to $1,211 million compared with $869 million during 2003. Development capital was directed to the following areas:

- In 2004, we increased exploitation spending in the Lloydminster heavy oil area to $362 million. We hold in excess of one million net undeveloped acres in the Lloydminster area and have established an integrated infrastructure throughout the area. Spending in 2004 continued to focus on primary production utilizing cold production techniques and thermal production utilizing cyclic steam and steam assisted gravity drainage techniques. Production from thermal operations accounted for approximately 20 percent of heavy oil production from the Lloydminster area, up from 17 percent in 2003. In addition, considerable capital spending is devoted to optimization of existing operations employing updated technology and efficient practices. In 2003 and 2002, we spent $303 million and $273 million, respectively, in the Lloydminster area.
- In 2004, we increased development spending in the foothills and Deep Basin region of Alberta and northeastern British Columbia and in the plains of northern Alberta to $464 million. We hold interests in well established operations at Rainbow Lake, Ram River, Valhalla/Wapiti, Ansell/Galloway, Boyer/Haro, Martin Hills and Slave Lake. Spending in 2004 continued to focus primarily on natural gas potential, approximately 85 percent of this area's total development spending. In the plains area spending was primarily directed to step-out exploitation of shallow natural gas reservoirs and follow-up development of discoveries. The majority of our new field wildcat exploration drilling for natural gas is conducted in the foothills and Deep Basin of Alberta and northeastern British Columbia. In 2003 and 2002, we spent $305 million and $306 million, respectively, in this area on exploration and development activities.

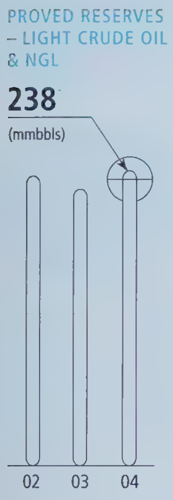
- In 2004, we increased exploitation spending in the east central and southern areas of Alberta and southwestern Saskatchewan to $364 million, up from $259 million in 2003. Our operations consist of mature oil operations, including a number of waterfloods and extensive shallow natural gas primarily located at Sylvan Lake, Drumheller, Provost, Taber and Suffield in Alberta and Swift Current in Saskatchewan. Spending is focused on step-out exploitation and operational optimization. Over half of capital spending is directed toward natural gas assets including an emphasis on the new plays in the Shackleton, Lacadena and White Bear areas.
- In 2004, we spent $26 million on the development of the Tucker oil sands project.

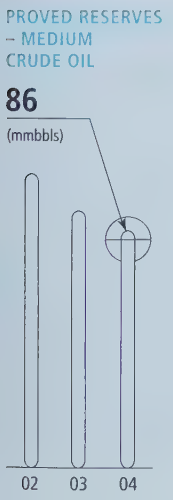
Exploration expenditures on our prospects in the Western Canada Sedimentary Basin in 2004 amounted to $322 million compared with $326 million in 2003. The primary exploration targets were natural gas prospects in the Alberta foothills and Deep Basin as well as step-out drilling throughout Husky's properties in the Basin. In 2004 we commenced an exploration program to assess prospects in the central Mackenzie Valley, Northwest Territories. In addition, pre-development spending at the Sunrise oil sands project amounted to $27 million. Capital expenditures on the Tucker and Sunrise oil sands projects totalled $41 million and $20 million during 2003 and 2002, respectively.

Capital Expenditures [(1)]

Year ended December 31 ($ millions)	2004	2003	2002
Upstream			
Exploration			
Western Canada	**$ 322**	$ 326	$ 304
East Coast Canada and Frontier	**24**	24	41
International	**18**	26	9
	364	376	354
Development			
Western Canada	**1,211**	869	739
East Coast Canada	**515**	533	417
International	**67**	–	66
	1,793	1,402	1,222
	2,157	1,778	1,576
Midstream			
Upgrader	**62**	25	41
Infrastructure and marketing	**31**	18	23
	93	43	64
Refined Products	**106**	58	44
Corporate	**23**	23	23
Capital expenditures	**2,379**	1,902	1,707
Settlement of asset retirement obligations	**(30)**	(34)	(16)
Capital expenditures per Consolidated Statements of Cash Flows	**$ 2,349**	$ 1,868	$ 1,691

(1) Excludes capitalized costs related to asset retirement obligations incurred during the period and corporate acquisitions.





Western Canada Drilling

[illegible]		[illegible]		[illegible]		[illegible]	
		Gross	*Net*	*Gross*	*Net*	*Gross*	*Net*
Exploration	Oil	**45**	**39**	12	11	21	20
	Gas	**234**	**180**	147	124	139	131
	Dry	**34**	**33**	22	21	15	14
		313	**252**	181	156	175	165
Development	Oil	**552**	**499**	520	490	497	453
	Gas	**807**	**740**	540	518	485	453
	Dry	**57**	**53**	60	57	58	55
		1,416	**1,292**	1,120	1,065	1,040	961
Total		**1,729**	**1,544**	1,301	1,221	1,215	1,126

East Coast Canada

Capital spending at Husky's White Rose oil field development offshore Newfoundland and Labrador amounted to $489 million in 2004 compared with $505 million in 2003. Capital spending with respect to the Terra Nova oil field amounted to $26 million in 2004 compared with $28 million in 2003.

International

Exploration capital spending in the South China Sea amounted to $18 million in 2004 compared with $26 million in 2003. Spending in 2004 was primarily related to drilling one exploration well on the 40/30 block and preparation for an exploration program that is expected to include three exploration wells in 2005.

In November 2004, we purchased our partner's share of a production-sharing contract in the Madura Strait offshore Indonesia for $62 million. The contract includes two natural gas discoveries and additional prospective exploration acreage.

Midstream Capital Expenditures

Midstream capital expenditures in 2004 of $93 million were primarily for upgrader debottlenecking and pipeline upgrades.

Refined Products Capital Expenditures

Refined products capital expenditures in 2004 of $106 million were primarily for marketing outlet improvements, refinery upgrades and construction of an ethanol plant.

Corporate Capital Expenditures

Corporate capital expenditures amounted to $23 million in 2004 and were primarily for computer hardware and software and office furniture and equipment.

OIL AND GAS RESERVES

Husky applied for and was granted an exemption from Canada's National Instrument 51-101 "Standards of Disclosure for Oil and Gas Activities" to provide oil and gas reserves disclosures in accordance with the United States Securities and Exchange Commission ("SEC") guidelines and the United States Financial Accounting Standards Board ("FASB") disclosure standards. The information disclosed may differ from information prepared in accordance with National Instrument 51-101. Husky's internally generated oil and gas reserves data was audited by an independent firm of oil and gas reserves evaluation engineers.

For more detail on our oil and gas reserves and the disclosures with respect to the FASB's Statement No. 69, "Disclosures about Oil and Gas Producing Activities", refer to our Annual Information Form available at www.sedar.com or Form 40-F available at www.sec.gov or on our website at www.huskyenergy.ca.

At December 31, 2004, the present value of future net cash flows after tax from the Company's proved oil and gas reserves, based on prices and costs in effect at year-end and discounted at 10 percent, was $5.2 billion compared with $5.8 billion at the end of 2003.

McDaniel & Associates Consultants Ltd., an independent firm of oil and gas reserves evaluation engineers, was engaged to conduct an audit of Husky's crude oil, natural gas and natural gas products reserves. McDaniel & Associates Consultants Ltd. issued an audit opinion stating that Husky's internally generated proved and probable reserves and net present values are, in aggregate, reasonable, and have been prepared in accordance with generally accepted oil and gas engineering and evaluation practices in the United States and as set out in the Canadian Oil and Gas Evaluation Handbook ("COGEH").

[illegible] – HEAVY CRUDE OIL

105

(mmbbls)

Reconciliation of Proved Reserves [1]

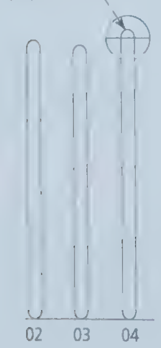
	[illegible]					Int'l	[illegible]		
	Western Canada				*East Coast*				
(constant price before royalties)	*Light Crude Oil & NGL*	*Medium Crude Oil*	*Heavy Crude Oil*	*Natural Gas*	*Light Crude Oil*	*Light Crude Oil*	*Crude Oil & NGL*	*Natural Gas*	
	(mmbbls)	*(mmbbls)*	*(mmbbls)*	*(bcf)*	*(mmbbls)*	*(mmbbls)*	*(mmbbls)*	*(bcf)*	*(mmboe)*
Proved reserves at December 31, 2003	173	94	227	2,059	26	24	544	2,059	887
Revision of previous estimate	1	1	(114)	(23)	(1)	3	(110)	(23)	(114)
Purchase of reserves in place	1	–	–	23	–	–	1	23	5
Sale of reserves in place	–	–	(1)	(14)	–	–	(1)	(14)	(3)
Extensions and discoveries	7	2	32	372	24	–	65	372	127
Improved recovery	1	2	1	4	3	–	7	4	8
Production	(12)	(13)	(40)	(252)	(5)	(7)	(77)	(252)	(119)
Proved reserves at December 31, 2004	**171**	**86**	**105**	**2,169**	**47**	**20**	**429**	**2,169**	**791**

(1) Proved reserves are the estimated quantities of crude oil, natural gas and NGL which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions.

PROVED RESERVES – NATURAL GAS

2,169

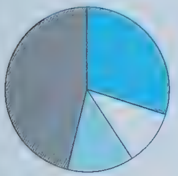
(bcf)



Our oil and gas reserves are estimated in accordance with the regulations and guidance of the SEC and the FASB, which, among other things, require reserves to be evaluated using prices in effect on the day the reserves are estimated. We have significant heavy oil reserves with an API gravity of 12 to 14 degrees. Heavy crude oil sells at a discount to light crude oils such as West Texas Intermediate, which has an API gravity of approximately 40 degrees, because it requires upgrading before it can be processed by conventional refineries. There is a finite capacity for upgrading in North America, which is often reached when heavy crude oil from other countries enters the North American market. Heavy crude oil requires blending with condensate or light synthetic crude oil ("diluent") in order for it to be transported in a pipeline. During the winter, heavy crude oil requires a higher proportion of diluent because of the cold temperatures and diluent prices are similar to light crude oil prices. Heavy crude oil is also processed into asphalt, which is typically in demand during the spring to fall paving months.

As a result of these factors, prices for heavy crude oil are historically low in December. During 2004 the price of heavy crude oil at Lloydminster averaged $28.75/bbl but on December 31, 2004, the date our oil and gas reserves were evaluated, the calculated price of Lloydminster heavy crude oil was $12.27/bbl while the price for Husky Synthetic Blend was just under $50.00/bbl. Husky Synthetic Blend is produced in our upgrading facility in Lloydminster, which was constructed to capture the difference in value between heavy crude oil and high quality synthetic crude oil. At $12.27/bbl, 86 percent of our proved undeveloped heavy crude oil reserves in the Lloydminster area did not produce positive value after the required capital investment and, in accordance with SEC and FASB regulations, were required to be subtracted as a negative revision from proved reserves until prices increase sufficiently to return those reserves to economic status. In addition, 39 percent of our proved developed heavy crude oil reserves were uneconomic on December 31, 2004, and were included in the negative revision. The SEC requires oil and gas reserves to be economic at the well head and does not permit consideration of other economic factors such as our upgrading facility, which at December 31, 2004, produced cash netback of approximately $30.00/bbl after royalties, lease operating costs, transportation and upgrading operating costs. When considering our upgrading, asphalt refining and other heavy oil infrastructure, our heavy oil production was economic to Husky at December 31, 2004. Notwithstanding the economics at December 31, 2004, on January 10, 2005, the price of Lloydminster heavy crude oil had returned to $21.56/bbl, a price that would be sufficient to return 98 percent of the reserves subtracted by negative revision to the proved reserve category.

TOTAL PROVED RESERVES



- Light Crude Oil & NGL **30%**
- Medium Crude Oil **11%**
- Heavy Crude Oil **13%**
- Natural Gas **46%**

The following table shows our reserves after considering our upgrading capacity:

	Canada					Int'l	Total		
	Western Canada				East Coast				
	Light Crude Oil & NGL	Medium Crude Oil	Heavy Crude Oil	Natural Gas	Light Crude Oil	Light Crude Oil	Crude Oil & NGL	Natural Gas	
	(mmbbls)	(mmbbls)	(mmbbls)	(bcf)	(mmbbls)	(mmbbls)	(mmbbls)	(bcf)	(mmboe)
Proved reserves at December 31, 2004	171	86	105	2,169	47	20	429	2,169	791
Heavy oil price revision at $12.27	–	–	120	3	–	–	120	3	120
Proved reserves excluding heavy oil revision at December 31, 2004	171	86	225	2,172	47	20	549	2,172	911

Before the effect of negative revisions from low heavy oil prices at December 31, 2004, during 2004 we added 146 million barrels of oil equivalent from discoveries, extensions, improved recovery, acquisitions and technical revisions. Reserves were added at White Rose, Lloydminster and in the foothills and Deep Basin of Alberta and northeastern British Columbia.

The additions to crude oil proved reserves amounted to 83 million barrels and were primarily from the Lloydminster reservoir extensions from step-out drilling and improved recovery. At White Rose, offshore Newfoundland and Labrador, 23 million barrels qualified as proved reserves.

The additions to natural gas proved reserves amounted to 379 billion cubic feet and were primarily related to our drilling program in the foothills and Deep Basin areas of Alberta and northeastern British Columbia. Natural gas reserve additions also resulted from field extensions at Ekwan Sierra, Rainbow, Abbey in southwestern Saskatchewan and areas throughout the Alberta foothills and Deep Basin. Negative technical revisions of previously estimated natural gas reserves were primarily related to reservoir performance.

Reconciliation of Proved Developed Reserves[1]

	[illegible]					[illegible]	[illegible]		
	Western Canada				East Coast				
(constant price before royalties)	Light Crude Oil & NGL	Medium Crude Oil	Heavy Crude Oil	Natural Gas	Light Crude Oil	Light Crude Oil	Crude Oil & NGL	Natural Gas	
	(mmbbls)	(mmbbls)	(mmbbls)	(bcf)	(mmbbls)	(mmbbls)	(mmbbls)	(bcf)	(mmboe)
Proved developed reserves at December 31, 2003	159	86	156	1,712	17	24	442	1,712	727
Revision of previous estimate	4	3	(43)	114	1	3	(32)	114	(14)
Purchase of reserves in place	1	–	–	22	–	–	1	22	5
Sale of reserves in place	–	–	(1)	(14)	–	–	(1)	(14)	(3)
Extensions and discoveries	3	2	19	159	–	–	24	159	51
Improved recovery	–	2	–	4	3	–	5	4	6
Production	(12)	(13)	(40)	(252)	(5)	(7)	(77)	(252)	(119)
Proved developed reserves at December 31, 2004	**155**	**80**	**91**	**1,745**	**16**	**20**	**362**	**1,745**	**653**

(1) Proved developed oil and gas reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.

The following table shows our proved developed reserves after considering our upgrading capacity:

	[illegible]					[illegible]	[illegible]		
	Western Canada				East Coast				
	Light Crude Oil & NGL	Medium Crude Oil	Heavy Crude Oil	Natural Gas	Light Crude Oil	Light Crude Oil	Crude Oil & NGL	Natural Gas	
	(mmbbls)	(mmbbls)	(mmbbls)	(bcf)	(mmbbls)	(mmbbls)	(mmbbls)	(bcf)	(mmboe)
Proved developed reserves at December 31, 2004	155	80	91	1,745	16	20	362	1,745	653
Heavy oil price revision at $12.27	–	–	60	3	–	–	60	3	61
Proved developed reserves excluding heavy oil revision at December 31, 2004	155	80	151	1,748	16	20	422	1,748	714

Crude Oil and Natural Gas Reserves Summary

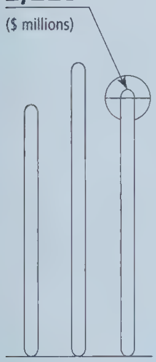
(constant price before royalties)	Proved Developed			Proved Undeveloped			Total Proved			Proved and Probable		
	2004	2003	2002	2004	2003	2002	2004	2003	2002	[illegible]	[illegible]	[illegible]
Crude oil (mmbbls)												
Light & NGL	**191**	200	193	**47**	23	42	**238**	223	235	**465**	474	511
Medium	**80**	86	94	**6**	8	13	**86**	94	107	**96**	108	131
Heavy	**91**	156	152	**14**	71	75	**105**	227	227	**150**	319	379
Bitumen	**–**	–	–	**–**	–	–	**–**	–	–	**79**	79	–
	362	442	439	**67**	102	130	**429**	544	569	**790**	980	1,021
Natural gas (bcf)	**1,745**	1,712	1,547	**424**	347	548	**2,169**	2,059	2,095	**2,724**	2,507	2,497
Total (mmboe)	**653**	727	697	**138**	160	221	**791**	887	918	**1,244**	1,397	1,437

LIQUIDITY

CASH FLOW FROM OPERATIONS

2,223

($ millions)



SOURCES OF CAPITAL

Liquidity describes a company's ability to access cash. Companies operating in the upstream oil and gas industry require sufficient cash in order to fund capital programs necessary to maintain and increase production and proved developed reserves, to acquire strategic oil and gas assets, repay maturing debt and pay dividends. Husky's upstream capital programs are funded principally by cash provided from operating activities. During times of low oil and gas prices part of a capital program can generally be deferred. However, due to the long cycle times and the importance to future cash flow in maintaining our production, it may be necessary to utilize alternative sources of capital to continue our strategic investment plan during periods of low commodity prices. As a result we continually examine our options with respect to sources of long and short-term capital resources. In addition, from time to time we engage in hedging a portion of our production to protect cash flow in the event of commodity price declines.

The following illustrates the Company's sources and uses of cash during the years ended December 31, 2004, 2003 and 2002:

Sources and Uses of Cash

($ millions)	2004	2003	2002
Cash sourced			
Cash flow from operations (1)	$ 2,223	$ 2,459	$ 2,096
Debt issue	2,200	669	972
Asset sales	36	511	93
Proceeds from exercise of stock options	18	51	9
Proceeds from monetization of financial instruments	8	44	–
Other	–	5	–
	4,485	3,739	3,170
Cash used			
Capital expenditures	2,349	1,868	1,691
Corporate acquisitions	102	809	3
Debt repayment	1,959	971	778
Special dividend on common shares	229	420	–
Ordinary dividends on common shares	195	160	151
Return on capital securities payment	26	29	31
Settlement of asset retirement obligations	40	34	16
Settlement of cross currency swap	–	32	–
Other	24	–	29
	4,924	4,323	2,699
Net cash (deficiency)	(439)	(584)	471
Increase (decrease) in non-cash working capital	443	281	(165)
Increase (decrease) in cash and cash equivalents	4	(303)	306
Cash and cash equivalents – beginning of year	3	306	–
Cash and cash equivalents – end of year	$ 7	$ 3	$ 306

(1) Cash flow from operations represents net earnings plus items not affecting cash, which include accretion, depletion, depreciation and amortization, future income taxes and foreign exchange.

Sources and Uses of Cash (continued)

($ millions)	2004	2003	2002
Increase (decrease) in non-cash working capital			
Cash positive working capital change			
Accounts receivable decrease	$ **209**	$ –	$ –
Inventory decrease	–	28	–
Prepaid expense decrease	–	–	1
Accounts payable and accrued liabilities increase	**323**	270	–
	532	298	1
Cash negative working capital change			
Accounts receivable increase	–	7	153
Inventory increase	**77**	–	2
Prepaid expense increase	**12**	10	–
Accounts payable and accrued liabilities decrease	–	–	11
	89	17	166
Increase (decrease) in non-cash working capital	$ **443**	$ 281	$ (165)

Capital Structure

($ millions)	December 31, 2004		
	Outstanding		Available
	(U.S. $)	(Cdn $)	(Cdn $)
Short-term bank debt	$ 5	$ 49	$ 123
Long-term bank debt			
Syndicated credit facility	–	70	880
Bilateral credit facility	–	40	110
Medium-term notes	–	300	
U.S. public notes	1,050	1,264	
U.S. senior secured bonds	117	140	
U.S. private placement notes	15	18	
Total short-term and long-term debt	$ 1,187	$ 1,881	$ 1,113
Capital securities	$ 225	$ 271	
Common shares and retained earnings		$ 6,200	

Working capital is the amount by which current assets exceed current liabilities. At December 31, 2004, our working capital deficiency was $815 million compared with $604 million at December 31, 2003. The increase in the deficiency is primarily due to the $0.54 per share special dividend declared on November 8, 2004 and the increase in the sale of net trade receivables. It is not unusual for Husky to have working capital deficits at the end of a reporting period. These working capital deficits are primarily the result of accounts payable related to capital expenditures for exploration and development. Settlement of these current liabilities is funded by cash provided by operating activities and to the extent necessary by bank borrowings. This position is a common characteristic of the oil and gas industry which, by the nature of its business, spends large amounts of capital.

As at December 31, 2004, our outstanding long-term debt totalled $1,832 million, including amounts due within one year, compared with $1,698 million at December 31, 2003.

At December 31, 2004, we had $70 million drawn under our $950 million revolving syndicated credit facility. Interest rates under this facility vary and are based on Canadian prime, Bankers' Acceptance, U.S. LIBOR or U.S. base rate, depending on the borrowing option selected, credit ratings assigned by certain rating agencies to our senior unsecured debt and whether the facility is revolving or non-revolving. The syndicated credit facility requires Husky to maintain a debt to cash flow ratio of less than three times and a consolidated tangible net worth, as of December 31, 2004, of at least $3.9 billion.

At December 31, 2004, we had $40 million drawn under our $150 million bilateral credit facilities. The terms of these facilities are substantially the same as the syndicated credit facility.

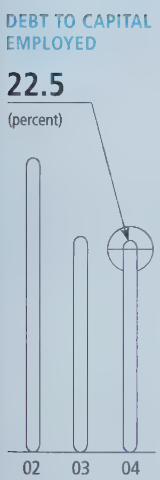
At December 31, 2004, we had borrowed $49 million and utilized $23 million in support of letters of credit under our $195 million in short-term borrowing facilities. The interest rates applicable to these facilities vary and are based on Canadian prime, Bankers' Acceptance, money market rates or U.S. dollar equivalents. In addition, we utilized $84 million under our dedicated letter of credit facilities.

Husky has an agreement to sell up to $350 million of net trade receivables on a revolving basis. The agreement calls for purchase discounts, based on Canadian commercial paper rates, plus a program fee to be paid on an ongoing basis. As at December 31, 2004, $350 million in outstanding accounts receivable had been sold under this agreement. The arrangement matures on January 31, 2009.

We believe that, based on our current forecast for commodity prices for 2005, our non-cancellable contractual obligations and commercial commitments and our 2005 capital program will be funded by operating activities and, to the extent required, available credit facilities. In the event of significantly lower cash flow, we would be able to defer certain of our projected capital expenditures without penalty.

We declared dividends that aggregated $1.00 per share totalling $424 million in 2004, including a special dividend of $0.54 per share. The Board of Directors of Husky has established a dividend policy that pays quarterly dividends of $0.12 ($0.48 annually) per common share. The declaration of dividends will be at the discretion of the Board of Directors, which will consider earnings, capital requirements, our financial condition and other relevant factors.

Cash and cash equivalents at December 31, 2004 totalled $7 million compared with $3 million at the beginning of the year.



Financial Ratios

Year ended December 31	2004	2003	2002
Cash flow – operating activities *($ millions)*	$ 2,352	$ 2,538	$ 1,882
– financing activities *($ millions)*	$ 149	$ (800)	$ 3
– investing activities *($ millions)*	$ (2,497)	$ (2,041)	$ (1,579)
Debt to capital employed *(percent)*	22.5	23.0	31.7
Corporate reinvestment ratio [(1)]	1.1	0.9	0.8

(1) Reinvestment ratio is based on net capital expenditures including corporate acquisitions.

CREDIT RATINGS

Husky's senior debt and capital securities have been rated investment grade by several rating agencies. These ratings are disclosed and explained in detail in our Annual Information Form.

CAPITAL REQUIREMENTS

Husky plans to invest capital in the following segments in 2005:

Year ended December 31 ($ millions)	2005 Estimate [(1)]
Upstream	
Western Canada	$ 1,688
East Coast Canada	556
International	44
	2,288
Midstream	140
Refined Products	240
Corporate	25
	$ 2,693

(1) Includes capitalized interest of $112 million and capitalized administration expenses of $36 million.

CONTRACTUAL OBLIGATIONS AND COMMERCIAL COMMITMENTS

In the normal course of business Husky is obligated to make future payments. These obligations represent contracts and other commitments that are known and non-cancellable.

Contractual Obligations [1] [2]

Payments due by period ($ millions)	Total	2005	2006-2007	2008-2009	Thereafter
Long-term debt [3]	$ 1,832	$ 56	$ 445	$ 233	$ 1,098
Capital securities [3]	271	–	–	271	–
Operating leases	554	68	152	151	183
Firm transportation agreements	1,061	213	375	262	211
Unconditional purchase obligations	1,481	593	684	87	117
Lease rentals	330	44	88	88	110
Exploration work agreements	50	27	15	–	8
Engineering and construction commitments	967	572	383	12	–
	$ 6,546	$ 1,573	$ 2,142	$ 1,104	$ 1,727

(1) The above table does not include asset retirement obligations. The Company currently includes such obligations in the amortizing base of its oil and gas properties. Effective January 1, 2004 with the adoption of the Canadian Institute of Chartered Accountants section 3110, "Asset Retirement Obligations", the Company records a separate liability for the fair value of its asset retirement obligations. See Note 12 to the Consolidated Financial Statements.

(2) The above table does not include post-retirement obligations. Husky has a defined contribution pension plan and a post-retirement health and dental care plan for its employees. In addition Husky has a defined benefit pension plan for approximately 200 employees. In 1991 admittance to the defined benefit pension plan ended after the majority of members transferred to the newly created defined contribution pension plan. See Note 17 to the Consolidated Financial Statements.

(3) Obligation related to long-term debt includes principal repayments only. If interest payable on our fixed interest rate debt was included, the total amount of the obligation would increase by $897 million. If the return on capital securities was included, assuming the capital securities were redeemed in 2008, the obligation would increase by $84 million.

Investment Canada Undertakings

In respect to the acquisition of Marathon Canada Limited, Husky confirmed certain undertakings to the Minister Responsible for the Investment Canada Act. The undertakings, which have been satisfied, included capital expenditures on the purchased and retained Marathon Canada Limited lands amounting to $65 million, spending on community activities amounting to $1.4 million and environmental expenditures of $40 million, all to occur in 2004.

Other Obligations

Husky is also subject to various contingent obligations that become payable only if certain events or rulings were to occur. The inherent uncertainty surrounding the timing and financial impact of these events or rulings prevents any meaningful measurement, which is necessary to assess impact on future liquidity. Such obligations include environmental contingencies, contingent consideration and potential settlements resulting from litigation.

OFF BALANCE SHEET ARRANGEMENTS

We do not utilize off balance sheet arrangements with unconsolidated entities to enhance perceived liquidity.

We engage in the ordinary course of business in the securitization of accounts receivable. In December 2004 our receivable securitization program was increased from $250 million to $350 million. The securitization agreement terminates on January 31, 2009. The accounts receivable are sold to an unrelated third party on a revolving basis. In accordance with the agreement we must provide a loss reserve to replace defaulted receivables.

The securitization program provides us with cost effective short-term funding for general corporate use. We account for these securitizations as asset sales. In the event the program is terminated our liquidity would not be substantially reduced.

TRANSACTIONS WITH RELATED PARTIES AND MAJOR CUSTOMERS

Husky, in the ordinary course of business, was party to a lease agreement with Western Canadian Place Ltd. The terms of the lease provided for the lease of office space at Western Canadian Place, management services and operating costs at commercial rates. Effective July 13, 2004, Western Canadian Place Ltd. sold Western Canadian Place to an unrelated party. Western Canadian Place Ltd. is indirectly controlled by Husky's principal shareholders. Prior to the sale, we paid approximately $10 million for office space in Western Canadian Place during 2004.

We did not have any customers that constituted more than five percent of total sales and operating revenues during 2004.

FINANCIAL AND DERIVATIVE INSTRUMENTS

Husky is exposed to market risks related to the volatility of commodity prices, foreign exchange rates and interest rates. Refer to the section "Business Environment". From time to time, we use derivative instruments to manage our exposure to these risks.

COMMODITY PRICE RISK MANAGEMENT

Husky uses derivative commodity instruments to manage exposure to price volatility on a portion of its oil and gas production and firm commitments for the purchase or sale of crude oil and natural gas.

We implemented a corporate hedging program for 2004 to manage the volatility of natural gas and crude oil prices.

Natural Gas

Husky's natural gas price risk management program for 2004 expired in April 2004. During 2004, Husky received net payments totalling $8 million on those contracts. As a result of a corporate acquisition, we assumed a natural gas derivative contract for a notional 7.5 mmcf/day that matures at the end of 2005. During 2004, we recorded payments totalling $9 million on this contract.

Crude Oil

Crude oil hedges on 85 mbbls/day were in effect from January to December 2004. During that period we recorded net payments totalling $560 million on these contracts.

Power Consumption

At December 31, 2004 Husky had hedged power consumption as follows:

	Notional Volumes (MW)	*Term*	*Price*	*Unrecognized Gain (Loss) ($ millions)*
Fixed price purchase	10.0	Jan. to Dec. 2005	$49.25/MWh	$ (0.1)
	12.5	Jan. to Dec. 2005	$50.50/MWh	(0.3)
	15.0	Jan. to Jun. 2005	$48.00/MWh	(0.2)
				$ (0.6)

FOREIGN CURRENCY RISK MANAGEMENT

At December 31, 2004, Husky had the following cross currency debt swaps in place:

- U.S. $150 million at 7.125 percent swapped at $1.45 to $218 million at 8.74 percent until November 15, 2006.
- U.S. $150 million at 6.250 percent swapped at $1.41 to $212 million at 7.41 percent until June 15, 2012.

At December 31, 2004 the cost of a U.S. dollar in Canadian currency was $1.2036.

In 2004 the cross currency swaps resulted in an offset to foreign exchange gains on translation of U.S. dollar denominated debt amounting to $27 million.

In addition, we entered into U.S. dollar forward contracts, which resulted in realized gains totalling approximately $14 million in 2004. In 2004, Husky unwound its long-dated forwards totalling U.S. $36 million, resulting in a gain of $8 million, which will be recognized into income on the dates the underlying hedged transactions are to take place.

INTEREST RATE RISK MANAGEMENT

In 2004 the interest rate risk management activities resulted in a decrease to interest expense of $22 million.

The cross currency swaps resulted in an addition to interest expense of $8 million in 2004.

We have interest rate swaps on $200 million of long-term debt, effective February 8, 2002, whereby 6.95 percent was swapped for CDOR + 175 bps until July 14, 2009. During 2004, these swaps resulted in an offset to interest expense amounting to $5 million.

We have interest rate swaps on U.S. $200 million of long-term debt, effective February 12, 2002, whereby 7.55 percent was swapped for an average U.S. LIBOR + 194 bps until November 15, 2011. During 2004, these swaps resulted in an offset to interest expense amounting to $11 million.

We have interest rate swaps on U.S. $300 million of long-term debt, effective June 18, 2004, whereby 6.15 percent was swapped for an average U.S. LIBOR + 63 bps until June 15, 2019. During 2004, these swaps resulted in an offset to interest expense amounting to $7 million.

The amortization of previous interest rate swap terminations resulted in an additional $7 million offset to interest expense in 2004.

APPLICATION OF CRITICAL ACCOUNTING ESTIMATES

Husky's financial statements have been prepared in accordance with Canadian generally accepted accounting principles. The significant accounting policies we use are disclosed in Note 3 to the Consolidated Financial Statements. Certain accounting policies require that we make appropriate decisions with respect to the formulation of estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses. The following discusses such accounting policies and is included in Management's Discussion and Analysis to aid you in assessing the critical accounting policies and practices of Husky and the likelihood of materially different results being reported. We review our estimates regularly. The emergence of new information and changed circumstances may result in actual results or changes to estimated amounts that differ materially from current estimates.

The following assessment of significant accounting policies is not meant to be exhaustive. Husky might realize different results from the application of new accounting standards promulgated, from time to time, by various rule-making bodies.

FULL COST ACCOUNTING FOR OIL AND GAS ACTIVITIES

The indicated change in the following estimates will result in a corresponding increase in the amount of DD&A expense charged to income in a given period:

An increase in:

- estimated costs to develop the proved undeveloped reserves
- estimated fair value of the asset retirement obligation related to the oil and gas properties
- estimated impairment of costs excluded from the DD&A calculation

A decrease in:

- previously estimated proved oil and gas reserves
- estimated proved reserves added compared to capital invested

Depletion Expense

Husky uses the full cost method of accounting for exploration and development activities as recommended by the Canadian Institute of Chartered Accountants ("CICA"). In accordance with this method of accounting, all costs associated with exploration and development are capitalized on a country by country basis. The aggregate of capitalized costs, net of accumulated DD&A, plus the estimated future costs required to develop the proved undeveloped oil and gas reserves less estimated equipment salvage values is charged to income using the unit of production method based on estimated proved oil and gas reserves.

Withheld Costs

Certain costs related to unproved properties and major development projects may be excluded from costs subject to depletion until proved reserves have been determined or their value is impaired. These properties are reviewed quarterly and any impairment is transferred to the costs being depleted or, if the properties are located in a cost centre where there is no reserve base, the impairment is charged directly to earnings.

Full Cost Accounting

Effective January 1, 2004, we adopted Accounting Guideline 16, "Oil and Gas Accounting – Full Cost". The new guideline modified the ceiling test, which requires, for each cost centre, capitalized costs be tested for recoverability. The test uses the estimated undiscounted future net cash flows from proved oil and gas reserves based on forecast prices and costs. When the carrying amount of a cost centre is not recoverable, the cost centre is written down to its fair value. Fair value is estimated using accepted present value techniques which incorporate risks and other uncertainties as well as the future value of reserves when determining estimated cash flows.

IMPAIRMENT OF LONG-LIVED ASSETS

We are required to review the carrying value of all property, plant and equipment, including the carrying value of oil and gas assets, for potential impairment. Impairment is indicated if the carrying value of the long-lived asset or oil and gas cost centre is not recoverable by the future undiscounted cash flows. If impairment is indicated, the amount by which the carrying value exceeds the estimated fair value of the long-lived asset is charged to earnings.

FAIR VALUE OF DERIVATIVE INSTRUMENTS

Periodically we utilize financial derivatives to manage market risk. The purpose of the derivative is to provide an element of stability to our cash flow in a volatile environment. We disclose the estimated fair value of open hedging contracts as at the end of a reporting period. Effective January 1, 2004 Husky adopted CICA Accounting Guideline 13, "Hedging Relationships" ("AcG-13"). AcG-13 has essentially the same criteria to be satisfied before the application of hedge accounting is permitted as the corresponding requirements of the FASB Statement No. 133, "Accounting for Derivative Instruments and Hedging Activities" ("FAS 133"). Refer to the description of FAS 133 in Note 20 to the Consolidated Financial Statements.

The estimation of the fair value of certain hedging derivatives requires considerable judgement. The estimation of the fair value of commodity price hedges requires sophisticated financial models that incorporate forward price and volatility data and which when compared with Husky's open hedging contracts, produce cash inflow or outflow variances over the contract period. The estimate of fair value for interest rate and foreign currency hedges is determined primarily through quotes from financial institutions.

Accounting rules for transactions involving derivative instruments are complex and subject to a range of interpretation. The FASB has established the Derivative Implementation Group task force, which, on an ongoing basis, considers issues arising from interpretation of these accounting rules. The potential exists that the task force may promulgate interpretations that differ from those of Husky. In this event our policy would be modified.

ASSET RETIREMENT OBLIGATIONS

Effective January 1, 2004, we adopted the recommendations of CICA section 3110, "Asset Retirement Obligations" ("ARO"), which is essentially identical to the United States accounting requirements of FAS 143.

We have significant obligations to remove tangible assets and restore land after operations cease and we retire or relinquish the asset. The ARO relates to all of our business operations, however, approximately 90 percent of the liability relates to the upstream business. The retirement of upstream assets consists primarily of plugging and abandoning wells, removing and disposing of surface and sub-sea equipment and facilities and restoration of land to a state required by regulation or contract. Estimating the future restoration and removal costs is difficult and requires management to make estimates and judgements because most of the removal obligations are many years in the future and contracts and regulations often require interpretation. Restoration technologies and costs are constantly changing, as are regulatory, political, environmental, safety and public relations considerations.

The new ARO rules require that an asset retirement obligation associated with the retirement of a tangible long-lived asset be recognized as a liability in the period in which a legal obligation is incurred and becomes determinable, with an offsetting increase in the carrying cost of the associated asset. The cost of the tangible asset, including the initially recognized ARO, is depleted such that the initial fair value of the ARO is recognized over the useful life of the asset. The initial fair value of the ARO is accreted to its expected settlement date. The accretion amount is expensed as a cost of operating and is added to the ARO liability. The fair value of the ARO is measured using expected future cash outflows discounted at our credit adjusted risk free interest rate.

Inherent in the present value calculation are numerous assumptions and judgements including the ultimate settlement amounts, future third party pricing, inflation factors, credit adjusted discount rates, timing of settlement and changes in the legal, regulatory, environmental and political environments. To the extent future revisions to these assumptions impact the present value of the existing ARO liability, a corresponding adjustment is made to the tangible asset balance.

Refer to Note 12 to the Consolidated Financial Statements, Other Long-term Liabilities, for a description of the effect of adopting the new ARO accounting policy.

LEGAL, ENVIRONMENTAL REMEDIATION AND OTHER CONTINGENT MATTERS

We are required to both determine whether a loss is probable based on judgement and interpretation of laws and regulations and determine that the loss can reasonably be estimated. When the loss is determined it is charged to earnings. The Company's management must continually monitor known and potential contingent matters and make appropriate provisions by charges to earnings when warranted by circumstances.

INCOME TAX ACCOUNTING

The determination of our income and other tax liabilities requires interpretation of complex laws and regulations often involving multiple jurisdictions. All tax filings are subject to audit and potential reassessment after the lapse of considerable time. Accordingly, the actual income tax liability may differ significantly from that estimated and recorded by management.

BUSINESS COMBINATIONS

Over recent years Husky has grown considerably through combining with other businesses. Husky acquired Temple Exploration Inc. in 2004 and Marathon Canada Limited in 2003. These transactions were accounted for using what is now the only accounting method available, the purchase method. Under the purchase method, the acquiring company includes the fair value of the assets of the acquired entity on its balance sheet. The determination of fair value necessarily involves many assumptions. The valuation of oil and gas properties primarily relies on placing a value on the oil and gas reserves. The valuation of oil and gas reserves entails the process described in the "Capital Resources" section under the caption "Oil and Gas Reserves" but in contrast incorporates the use of economic forecasts that estimate future changes in prices and costs. In addition, this methodology is used to value unproved oil and gas reserves. The valuation of these reserves, by their nature, is less certain than the valuation of proved reserves.

GOODWILL

The process of accounting for the purchase of a company, described above, results in recognizing the fair value of the acquired company's assets on the balance sheet of the acquiring company. Any excess of the purchase price over fair value is recorded as goodwill. Since goodwill results from the culmination of a process that is inherently imprecise the determination of goodwill is also imprecise. In accordance with the issuance of FASB Statement No. 142 and CICA section 3062, "Goodwill and Other Intangible Assets", goodwill is no longer amortized but assessed periodically for impairment. The process of assessing goodwill for impairment necessarily requires Husky to determine the fair value of its assets and liabilities. Such a process involves considerable judgement.

NEW ACCOUNTING STANDARDS

ASSET RETIREMENT OBLIGATIONS

Effective January 1, 2004, we retroactively adopted CICA section 3110, "Asset Retirement Obligations". This standard harmonizes Canadian GAAP with FASB Statement No. 143, "Accounting for Asset Retirement Obligations", which became effective January 1, 2003.

The new standard changes the method for recognition of legal obligations, or liabilities, associated with the retirement of tangible long-lived assets. When incurred, the liabilities are recorded at their estimated fair value, which is based on a discounted value of the expected costs to be paid when the assets are retired. The amount is added to the carrying values of the assets and depreciated over the estimated remaining lives of the assets. The liability increases each period as the amount of the discount decreases over time. The resulting expense is referred to as accretion expense and is included in operating expenses. The liability and associated capital assets are also adjusted for any changes in the estimated amount or timing of the underlying future cash flows. Previously, asset retirement obligations were accrued over the estimated remaining useful lives of the assets. See Note 12 to the Consolidated Financial Statements for further information.

ACCOUNTING FOR STOCK-BASED COMPENSATION

In October 1995, the FASB issued Statement No. 123, "Accounting for Stock-based Compensation Plans" ("FAS 123"), which established a fair value method of accounting for stock-based compensation and required companies that continued to account for stock-based compensation in accordance with the "intrinsic method" to provide a pro forma disclosure that reflects the difference between the two methods. This statement also includes transactions that involve the issuance of equity instruments in exchange for goods and services.

In December 2004, the FASB issued FAS 123(R), "Share-based Payment", which replaces FAS 123 and supersedes Accounting Principles Board ("APB") Opinion 25. FAS 123(R) requires compensation costs related to share-based payments be recognized in the financial statements and the cost be measured based on the fair value of the equity or liability instrument issued. Under FAS 123(R), all share-based payment plans must be valued using an option-pricing model. For U.S. GAAP, the liability related to the options issued under our tandem plan will be measured using an option-pricing model. Under Canadian GAAP, the liability will be measured using the intrinsic method. Over the life of the option the amount of compensation expense will differ between U.S. and Canadian GAAP. Upon exercise or surrender of the option, the compensation expense recorded is based on the cash payment, which will be the same under both U.S. and Canadian GAAP, and there will no longer be a difference between U.S. and Canadian GAAP. FAS 123(R) is effective July 1, 2005.

EMPLOYER'S DISCLOSURES ABOUT PENSION AND OTHER POST-RETIREMENT BENEFITS

In December 2003, the FASB issued Statement 132(R) that was developed in response to the need for additional information about pension plan assets, obligations, benefit payments, contributions and net benefit costs. The effective dates of FAS 132(R) have been phased in since December 2003 and the final aspects of FAS 132(R) became effective for fiscal years ending after June 15, 2004. The pertinent revision included in our 2004 financial statements required the disclosure of estimated future benefit payments for the next five years and for years six to ten in aggregate.

INVENTORY COSTS

In November 2004, the FASB issued FAS 151, "Inventory Costs" that clarifies the accounting for abnormal amounts of idle facility expense, freight, handling costs and wasted material as they relate to inventory costing. FAS 151 requires these items to be recognized as current expenses. Additionally, the allocation of fixed production overheads to the cost of inventory should be based on the normal capacity of the production facilities.

SAB 106

In September 2004, the SEC issued Staff Accounting Bulletin 106 ("SAB 106") regarding the application of FAS 143 by oil and gas producing entities that follow the full cost accounting method under Rule 4-10(c) of Regulation S-X. SAB 106 states that after the adoption of FAS 143 the future cash outflows associated with the settlement of asset retirement obligations that have been accrued on the balance sheet should be excluded from the computation of the present value of estimated future net revenues from the development and production of proved oil and gas reserves for purposes of the full cost ceiling test calculation. Husky excludes the future cash outflows associated with settling asset retirement obligations from the present value of estimated future net revenues because the fair value of the asset retirement cash outflows was capitalized by increasing long-lived oil and gas assets and those costs must be recovered by the estimated future net revenues from the development and production of proved oil and gas reserves. The estimated future net revenues from proved oil and gas reserves should, however, be reduced by the estimated dismantlement and abandonment costs, net of estimated salvage values, that are estimated to result from future development activities. Costs subject to depletion and depreciation include the estimated costs required to develop proved undeveloped reserves and the associated addition to the asset retirement obligations.

ACCOUNTING FOR VARIABLE INTEREST ENTITIES

In January 2003, the FASB issued Financial Interpretation 46, "Accounting for Variable Interest Entities" ("FIN 46") that requires the consolidation of Variable Interest Entities ("VIEs"). VIEs are entities that have insufficient equity or their equity investors lack one or more of the specified elements that a controlling entity would have. The VIEs are controlled through financial interests that indicate control (referred to as "variable interests"). Variable interests are the rights or obligations that expose the holder of the variable interest to expected losses or expected residual gains of the entity. The holder of the majority of an entity's variable interests is considered the primary beneficiary of the VIE and is required to consolidate the VIE. In December 2003, the FASB issued FIN 46(R) which superseded FIN 46 and restricts the scope of the definition of entities that would be considered VIEs that require consolidation. We do not believe FIN 46(R) results in the consolidation of any additional entities.

ACCOUNTING FOR EXCHANGES OF NONMONETARY ASSETS

In December 2004, the FASB issued FAS 153 which deals with the accounting for the exchanges of nonmonetary assets. FAS 153 is an amendment of APB Opinion 29. APB Opinion 29 requires that exchanges of nonmonetary assets should be measured based on the fair value of the assets exchanged. FAS 153 amends APB Opinion 29 to eliminate the exception from using fair market value for nonmonetary exchanges of similar productive assets and introduces a broader exception for exchanges of nonmonetary assets that do not have commercial substance. FAS 153 is effective for nonmonetary asset exchanges occurring in fiscal periods beginning after June 15, 2005. We do not believe that the application of FAS 153 will have an impact on the financial statements.

QUARTERLY FINANCIAL SUMMARY

	2003				2002			
	Q4	*Q3*	*Q2*	*Q1*	*Q4*	*Q3*	*Q2*	*Q1*
Sales and operating revenues, net of royalties	$ 2,018	$ 2,191	$ 2,210	$ 2,021	$ 1,800	$ 1,871	$ 1,769	$ 2,218
Net earnings	$ 218	$ 286	$ 239	$ 263	$ 236	$ 249	$ 441	$ 408
Earnings								
Per share								
– Basic	$ 0.53	$ 0.70	$ 0.54	$ 0.60	$ 0.60	$ 0.56	$ 1.09	$ 1.01
– Diluted	$ 0.52	$ 0.70	$ 0.54	$ 0.60	$ 0.59	$ 0.56	$ 1.09	$ 1.01
Share price								
– High	$ 35.65	$ 31.15	$ 28.30	$ 28.04	$ 23.95	$ 20.95	$ 18.14	$ 17.49
– Low	$ 30.05	$ 25.42	$ 23.74	$ 22.73	$ 20.40	$ 17.35	$ 16.15	$ 16.03
– Close (end of period)	$ 34.25	$ 30.79	$ 25.65	$ 26.20	$ 23.47	$ 20.50	$ 17.50	$ 16.93
Shares traded *(thousands)*	37,417	35,074	26,654	22,824	22,171	35,453	24,858	18,371
Dividends declared per common share	$ 0.12	$ 0.12	$ 0.12	$ 0.10	$ 0.10	$ 0.10	$ 0.09	$ 0.09
Special dividend per common share	$ 0.54	$ –	$ –	$ –	$ –	$ 1.00	$ –	$ –
Number of weighted average common shares outstanding *(thousands)*								
– Basic	423,708	423,610	423,413	422,711	421,702	419,729	418,539	418,163
– Diluted	426,825	426,043	425,169	424,720	423,830	422,010	420,331	419,985

RESULTS OF OPERATIONS FOR 2003 COMPARED WITH 2002

The consolidated revenue during 2003 was 20 percent higher than in 2002 primarily as a result of higher realized prices for crude oil and natural gas in the upstream segment.

Net earnings in 2003 were $1,334 million compared with $814 million in 2002. The increase of $520 million was attributable to the following:

Upstream – increase of $368 million

- higher realized crude oil and natural gas prices and production
- lower income taxes

partially offset by:

- higher operating costs and DD&A
- higher royalties

Midstream – increase of $24 million

- wider upgrading differential
- higher upgrader throughput and sales volume
- higher heavy crude oil pipeline throughput
- higher cogeneration income

partially offset by:

- higher unit operating costs, which were primarily energy related
- lower crude oil and natural gas commodity marketing margins

Refined Products – decrease of $1 million

- lower fuel margins

partially offset by:

- higher asphalt margins and sales volumes
- lower income taxes

Corporate – increase of $129 million

- foreign exchange gains on translation of U.S. dollar denominated long-term debt
- lower intersegment profit eliminations
- lower net interest expense due to higher capitalization

partially offset by:

- higher income taxes

DISCLOSURE OF OUTSTANDING SHARE DATA

Authorized:

- unlimited number of common shares
- unlimited number of preferred shares

Issued and outstanding: February 10, 2005

common shares	423,794,385
preferred shares	none
stock options	9,783,958
stock options exercisable	1,291,552
warrants	24,500

At February 10, 2005, 23,049,479 common shares were reserved for issuance under the stock option plan. Options awarded under the stock option plan have a maximum term of five years and vest evenly over the first three years.

In 2000, Husky issued Renaissance Energy Limited ("Renaissance") replacement options, which replaced options held to acquire Renaissance common shares. The former shareholders of Husky were issued warrants to acquire 1.86 common shares of Husky for each common share issued under the Renaissance replacement option plan. Warrants are only exercisable if Renaissance replacement options are exercised. At February 10, 2005, the maximum number of common shares that could be issued for warrants was 45,497 common shares. At February 10, 2005, the Renaissance replacement options had a term of one month.

FORWARD-LOOKING STATEMENTS

CAUTIONARY STATEMENT FOR THE PURPOSES OF THE 'SAFE HARBOR' PROVISIONS OF THE PRIVATE SECURITIES LITIGATION REFORM ACT OF 1995

This Annual Report contains certain forward-looking statements relating, but not limited, to Husky's operations, anticipated financial performance, business prospects and strategies and which are based on Husky's current expectations, estimates, projections and assumptions and were made by Husky in light of experience and perception of historical trends. Some of Husky's forward-looking statements may be identified by words like "expects", "anticipates", "plans", "intends", "believes", "projects", "could", "vision", "goal", "objective" and similar expressions. Husky's business is subject to risks and uncertainties, some of which are similar to other energy companies and some of which are unique to Husky. All statements that address expectations or projections about the future, including statements about strategy for growth, expected expenditures, commodity prices, costs, schedules and production volumes, operating or financial results, are forward-looking statements.

The reader is cautioned not to place undue reliance on Husky's forward-looking statements. Husky's actual results may differ materially from those expressed or implied by Husky's forward-looking statements as a result of known and unknown risks, uncertainties and other factors. By their nature, forward-looking statements involve numerous assumptions, inherent risks and uncertainties, both general and specific, that contribute to the possibility that the predicted outcomes will not occur. The risks,

uncertainties and other factors, many of which are beyond Husky's control, that could influence actual results include, but are not limited to:

- fluctuations in commodity prices
- changes in general economic, market and business conditions
- fluctuations in supply and demand for Husky's products
- fluctuations in the cost of borrowing
- Husky's use of derivative financial instruments to hedge exposure to changes in commodity prices and fluctuations in interest rates and foreign currency exchange rates
- political and economic developments, expropriations, royalty and tax increases, retroactive tax claims and changes to import and export regulations and other foreign laws and policies in the countries in which Husky operates
- Husky's ability to receive timely regulatory approvals
- the integrity and reliability of Husky's capital assets
- the cumulative impact of other resource development projects
- estimated production levels and Husky's success at exploration and development drilling and related activities
- the maintenance of satisfactory relationships with unions, employee associations and joint venturers
- competitive actions of other companies, including increased competition from other oil and gas companies or from companies that provide alternate sources of energy
- the uncertainties resulting from potential delays or changes in plans with respect to exploration or development projects or capital expenditures
- actions by governmental authorities, including changes in environmental and other regulations
- the ability and willingness of parties with whom Husky has material relationships to fulfil their obligations
- the occurrence of unexpected events such as fires, blowouts, freeze-ups, equipment failures and other similar events affecting Husky or other parties whose operations or assets directly or indirectly affect Husky

OIL AND GAS RESERVE REPORTING

DISCLOSURE OF PROVED OIL AND GAS RESERVES AND OTHER OIL AND GAS INFORMATION

The Company's disclosure of proved oil and gas reserves and other information about its oil and gas activities has been made based on reliance of an exemption granted by the Canadian Securities Administrators. The exemption permits the Company to make these disclosures in accordance with requirements in the United States. These requirements and, consequently, the information presented may differ from Canadian requirements under National Instrument 51-101, "Standards of Disclosure for Oil and Gas Activities". The proved oil and gas reserves disclosed in this Annual Report have been evaluated using the United States standards contained in Rule 4-10 of Regulation S-X of the Securities Exchange Act of 1934. The probable oil and gas reserves disclosed in this Annual Report have been evaluated in accordance with the COGEH and NI 51-101.

The Company uses the terms barrels of oil equivalent ("boe") and thousand cubic feet of gas equivalent ("mcfge"), which are calculated on an energy equivalence basis whereby one barrel of crude oil is equivalent to six thousand cubic feet of natural gas. Readers are cautioned that the terms boe and mcfge may be misleading, particularly if used in isolation. This measure is primarily applicable at the burner tip and does not represent value equivalence at the well head.

Cautionary note to U.S. Investors – The United States Securities and Exchange Commission permits oil and gas companies, in their filings with the SEC, to disclose only proved reserves that a company has demonstrated by actual production or conclusive formation tests to be economically and legally producible under existing economic and operating conditions. The Company uses certain terms in this Annual Report, such as probable (possible, recoverable, established, etc.) that the SEC's guidelines strictly prohibit from inclusion in filings with the SEC.

NON-GAAP MEASURES

DISCLOSURE OF CASH FLOW FROM OPERATIONS

This Annual Report contains the term "cash flow from operations", which should not be considered an alternative to, or more meaningful than "cash flow – operating activities", as determined in accordance with generally accepted accounting principles as an indicator of the Company's financial performance. The Company's determination of cash flow from operations may not be comparable to that reported by other companies. Cash flow from operations equals net earnings plus items not affecting cash which include accretion, depletion, depreciation and amortization, future income taxes, foreign exchange and other non-cash items.

The following table shows the reconciliation of cash flow from operations to cash flow – operating activities for the years ended December 31:

($ millions)		2004	2003	2002
Non-GAAP	Cash flow from operations	**$ 2,223**	$ 2,459	$ 2,096
	Settlement of asset retirement obligations	**(40)**	(34)	(16)
	Change in non-cash working capital	**169**	113	(198)
GAAP	Cash flow – operating activities	**$ 2,352**	$ 2,538	$ 1,882

EVALUATION OF DISCLOSURE CONTROLS AND PROCEDURES

The Company's chief executive officer and chief financial officer (its principal executive officer and principal financial officer, respectively) have concluded, based on their evaluation as of a date within 90 days prior to the filing of this Annual Report (the "evaluation date"), that the Company's disclosure controls and procedures are effective to ensure that information required to be disclosed by it in reports filed or submitted by it under the Securities Exchange Act of 1934, as amended, is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission's rules and forms, and includes controls and procedures designed to ensure that information required to be disclosed by it in such reports is accumulated and communicated to the Company's management, including its chief executive officer and chief financial officer, as appropriate to allow timely decisions regarding required disclosure.

There have been no significant changes to Husky's internal controls or in other factors that could significantly affect these controls subsequent to the evaluation date and the filing date of this Annual Report.

PUBLIC SECURITIES FILINGS

You may access additional information about our Company, including our Annual Information Form, which is filed with the Canadian Securities Administrators at www.sedar.com and the Form 40-F, which is filed with the United States Securities and Exchange Commission at www.sec.gov.

HUSKY ENERGY INC. 2004

CONSOLIDATED FINANCIAL STATEMENTS AND NOTES

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MANAGEMENT'S REPORT

The management of Husky Energy Inc. is responsible for the financial information and operating data presented in this Annual Report.

The consolidated financial statements have been prepared by management in accordance with Canadian generally accepted accounting principles. When alternative accounting methods exist, management has chosen those it deems most appropriate in the circumstances. Financial statements are not precise as they include certain amounts based on estimates and judgements. Management has determined such amounts on a reasonable basis in order to ensure that the financial statements are presented fairly, in all material respects. Financial information presented elsewhere in this Annual Report has been prepared on a basis consistent with that in the consolidated financial statements.

Husky Energy Inc. maintains systems of internal accounting and administrative controls. These systems are designed to provide reasonable assurance that the financial information is relevant, reliable and accurate and that the Company's assets are properly accounted for and adequately safeguarded. The system of internal controls is further supported by an internal audit function.

The Audit Committee of the Board of Directors, composed of independent non-management directors, meets regularly with management, as well as the external auditors, to discuss auditing (external, internal and joint venture), internal controls, accounting policy, financial reporting matters and reserves determination process. The Committee reviews the annual consolidated financial statements with both management and the independent auditors and reports its findings to the Board of Directors before such statements are approved by the Board.

The consolidated financial statements have been audited by KPMG LLP, the independent auditors, in accordance with Canadian generally accepted auditing standards on behalf of the shareholders. KPMG LLP has full and free access to the Audit Committee.

John C. S. Lau
President & Chief Executive Officer

Neil McGee
Vice President & Chief Financial Officer

Calgary, Alberta Canada
January 17, 2005

AUDITORS' REPORT TO THE SHAREHOLDERS

We have audited the consolidated balance sheets of Husky Energy Inc., as at December 31, 2004, 2003 and 2002 and the consolidated statements of earnings, retained earnings, and cash flows for each of the years in the three-year period ended December 31, 2004. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2004, 2003 and 2002 and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2004 in accordance with Canadian generally accepted accounting principles.

KPMG LLP

Chartered Accountants
Calgary, Alberta Canada
January 17, 2005

CONSOLIDATED BALANCE SHEETS

As at December 31 (millions of dollars)	*2004*	*2003*	*2002*
ASSETS			
Current assets			
Cash and cash equivalents	**$ 7**	$ 3	$ 306
Accounts receivable *(note 4)*	**446**	618	572
Inventories *(note 5)*	**274**	198	227
Prepaid expenses	**52**	33	23
	779	852	1,128
Property, plant and equipment, net (full cost accounting) *(notes 1, 6)*	**12,193**	10,862	9,421
Goodwill *(note 7)*	**160**	120	–
Other assets *(note 11)*	**106**	112	84
	$ 13,238	$ 11,946	$ 10,633
LIABILITIES AND SHAREHOLDERS' EQUITY			
Current liabilities			
Bank operating loans *(note 9)*	**$ 49**	$ 71	$ –
Accounts payable and accrued liabilities *(note 10)*	**1,489**	1,126	794
Long-term debt due within one year *(note 11)*	**56**	259	421
	1,594	1,456	1,215
Long-term debt *(note 11)*	**1,776**	1,439	1,964
Other long-term liabilities *(note 12)*	**632**	519	304
Future income taxes *(note 13)*	**2,758**	2,621	2,014
Commitments and contingencies *(note 14)*			
Shareholders' equity			
Capital securities and accrued return *(note 15)*	**278**	298	364
Common shares *(note 16)*	**3,506**	3,457	3,406
Retained earnings	**2,694**	2,156	1,366
	6,478	5,911	5,136
	$ 13,238	$ 11,946	$ 10,633

The accompanying notes to the consolidated financial statements are an integral part of these statements. 2003 and 2002 amounts as restated (note 3).

On behalf of the Board:

John C. S. Lau
Director

R.D. Fullerton
Director

CONSOLIDATED STATEMENTS OF EARNINGS

Year ended December 31 (millions of dollars, except per share amounts)	*2004*	*2003*	*2002*
Sales and operating revenues, net of royalties	**$ 8,440**	$ 7,658	$ 6,384
Costs and expenses			
Cost of sales and operating expenses *(note 12)*	**5,706**	4,847	4,026
Selling and administration expenses	**135**	119	94
Stock-based compensation *(note 16)*	**67**	–	–
Depletion, depreciation and amortization *(notes 1, 6)*	**1,179**	1,021	908
Interest – net *(note 11)*	**33**	73	104
Foreign exchange *(note 11)*	**(99)**	(215)	13
Other – net	**8**	3	1
	7,029	5,848	5,146
Earnings before income taxes	**1,411**	1,810	1,238
Income taxes *(note 13)*			
Current	**302**	147	66
Future	**103**	329	358
	405	476	424
Net earnings	**$ 1,006**	$ 1,334	$ 814
Earnings per share *(note 16)*			
Basic	**$ 2.37**	$ 3.26	$ 1.91
Diluted	**$ 2.36**	$ 3.25	$ 1.90

CONSOLIDATED STATEMENTS OF RETAINED EARNINGS

Year ended December 31 (millions of dollars)	*2004*	*2003*	*2002*
Beginning of year	**$ 2,156**	$ 1,366	$ 722
Net earnings	**1,006**	1,334	814
Dividends on common shares *(note 16)*	**(424)**	(580)	(151)
Return and foreign exchange on capital securities *(note 15)*	**(6)**	38	(29)
Related future income taxes *(note 13)*	**6**	(2)	11
Stock-based compensation – retroactive adoption *(note 16)*	**(44)**	–	–
Asset retirement obligations – retroactive adoption *(note 12)*	**–**	–	(1)
End of year	**$ 2,694**	$ 2,156	$ 1,366

The accompanying notes to the consolidated financial statements are an integral part of these statements. 2003 and 2002 amounts as restated (note 3).

CONSOLIDATED STATEMENTS OF CASH FLOWS

Year ended December 31 (millions of dollars)	*2004*	*2003*	*2002*
Operating activities			
Net earnings	**$ 1,006**	$ 1,334	$ 814
Items not affecting cash			
Accretion	**27**	22	17
Depletion, depreciation and amortization	**1,179**	1,021	908
Future income taxes	**103**	329	358
Foreign exchange *(note 11)*	**(103)**	(242)	–
Other	**11**	(5)	(1)
Settlement of asset retirement obligations	**(40)**	(34)	(16)
Change in non-cash working capital *(note 8)*	**169**	113	(198)
Cash flow – operating activities	**2,352**	2,538	1,882
Financing activities			
Bank operating loans financing – net	**(22)**	71	(100)
Long-term debt issue	**2,200**	598	972
Long-term debt repayment	**(1,937)**	(971)	(678)
Settlement of cross currency swap	**–**	(32)	–
Return on capital securities payment	**(26)**	(29)	(31)
Debt issue costs	**(5)**	–	(9)
Proceeds from exercise of stock options	**18**	51	9
Proceeds from monetization of financial instruments	**8**	44	–
Dividends on common shares	**(424)**	(580)	(151)
Change in non-cash working capital *(note 8)*	**337**	48	(9)
Cash flow – financing activities	**149**	(800)	3
Available for investing	**2,501**	1,738	1,885
Investing activities			
Capital expenditures	**(2,349)**	(1,868)	(1,691)
Corporate acquisitions	**(102)**	(809)	(3)
Asset sales	**36**	511	93
Other	**(19)**	5	(20)
Change in non-cash working capital *(note 8)*	**(63)**	120	42
Cash flow – investing activities	**(2,497)**	(2,041)	(1,579)
Increase (decrease) in cash and cash equivalents	**4**	(303)	306
Cash and cash equivalents at beginning of year	**3**	306	–
Cash and cash equivalents at end of year	**$ 7**	$ 3	$ 306

The accompanying notes to the consolidated financial statements are an integral part of these statements. 2003 and 2002 amounts as restated (note 3).

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

Except where indicated and per share amounts, all dollar amounts are in millions.

Note 1 Segmented Financial Information [1]

	Upstream			Midstream		
				Upgrading		
	2004	2003	2002	2004	2003	2002
Year ended December 31						
Sales and operating revenues, net of royalties	$ 3,120	$ 3,186	$ 2,665	$ 1,058	$ 1,013	$ 909
Costs and expenses						
Operating, cost of sales, selling and general	967	873	743	884	901	811
Depletion, depreciation and amortization	1,077	918	822	19	20	18
Interest – net	–	–	–	–	–	–
Foreign exchange	–	–	–	–	–	–
	2,044	1,791	1,565	903	921	829
Earnings (loss) before income taxes	1,076	1,395	1,100	155	92	80
Current income taxes	211	95	55	–	1	1
Future income taxes	152	233	346	43	20	25
Net earnings (loss)	$ 713	$ 1,067	$ 699	$ 112	$ 71	$ 54
Capital employed – As at December 31	$ 7,747	$ 6,709	$ 6,100	$ 480	$ 456	$ 319
Property, plant and equipment – As at December 31						
Cost						
Canada	$ 16,002	$ 13,831	$ 11,657	$ 1,084	$ 1,023	$ 999
International	587	503	474	–	–	–
	$ 16,589	$ 14,334	$ 12,131	$ 1,084	$ 1,023	$ 999
Accumulated depletion, depreciation and amortization						
Canada	$ 5,722	$ 4,718	$ 3,968	$ 409	$ 391	$ 372
International	311	252	186	–	–	–
	$ 6,033	$ 4,970	$ 4,154	$ 409	$ 391	$ 372
Net						
Canada	$ 10,280	$ 9,113	$ 7,689	$ 675	$ 632	$ 627
International	276	251	288	–	–	–
	$ 10,556	$ 9,364	$ 7,977	$ 675	$ 632	$ 627
Capital expenditures – Year ended December 31 [3]	$ 2,157	$ 1,778	$ 1,576	$ 62	$ 25	$ 41
Total assets – As at December 31 [4]						
Canada	$ 10,897	$ 9,685	$ 7,931	$ 708	$ 650	$ 659
International	275	264	341	–	–	–
	$ 11,172	$ 9,949	$ 8,272	$ 708	$ 650	$ 659

(1) 2003 and 2002 amounts as restated (note 3).

(2) Eliminations relate to sales and operating revenues between segments recorded at transfer prices based on current market prices, and to unrealized intersegment profits in inventories.

(3) Excludes capitalized costs related to asset retirement obligations incurred during the period and corporate acquisitions.

(4) Includes goodwill on corporate acquisitions related to Upstream.

Midstream Infrastructure and Marketing			*Refined Products*			*Corporate and Eliminations* (2)			*Total*		
2004	2003	2002	**2004**	2003	2002	**2004**	2003	2002	**2004**	2003	2002
$ 6,126	$ 4,946	$ 4,230	**$ 1,797**	$ 1,502	$ 1,310	**$ (3,661)**	$ (2,989)	$ (2,730)	**$ 8,440**	$ 7,658	$ 6,384
5,914	4,747	4,038	**1,694**	1,426	1,224	**(3,543)**	(2,978)	(2,695)	**5,916**	4,969	4,121
21	21	20	**38**	26	31	**24**	36	17	**1,179**	1,021	908
–	–	–	**–**	–	–	**33**	73	104	**33**	73	104
–	–	–	**–**	–	–	**(99)**	(215)	13	**(99)**	(215)	13
5,935	4,768	4,058	**1,732**	1,452	1,255	**(3,585)**	(3,084)	(2,561)	**7,029**	5,848	5,146
191	178	172	**65**	50	55	**(76)**	95	(169)	**1,411**	1,810	1,238
31	27	6	**11**	9	4	**49**	15	–	**302**	147	66
32	37	59	**13**	9	18	**(137)**	30	(90)	**103**	329	358
$ 128	$ 114	$ 107	**$ 41**	$ 32	$ 33	**$ 12**	$ 50	$ (79)	**$ 1,006**	$ 1,334	$ 814
$ 255	$ 348	$ 429	**$ 354**	$ 315	$ 316	**$ (477)**	$ (148)	$ 357	**$ 8,359**	$ 7,680	$ 7,521
$ 647	$ 622	$ 598	**$ 878**	$ 773	$ 706	**$ 253**	$ 205	$ 172	**$ 18,864**	$ 16,454	$ 14,132
–	–	–	**–**	–	–	**–**	–	–	**587**	503	474
$ 647	$ 622	$ 598	**$ 878**	$ 773	$ 706	**$ 253**	$ 205	$ 172	**$ 19,451**	$ 16,957	$ 14,606
$ 226	$ 203	$ 184	**$ 432**	$ 392	$ 361	**$ 158**	$ 139	$ 114	**$ 6,947**	$ 5,843	$ 4,999
–	–	–	**–**	–	–	**–**	–	–	**311**	252	186
$ 226	$ 203	$ 184	**$ 432**	$ 392	$ 361	**$ 158**	$ 139	$ 114	**$ 7,258**	$ 6,095	$ 5,185
$ 421	$ 419	$ 414	**$ 446**	$ 381	$ 345	**$ 95**	$ 66	$ 58	**$ 11,917**	$ 10,611	$ 9,133
–	–	–	**–**	–	–	**–**	–	–	**276**	251	288
$ 421	$ 419	$ 414	**$ 446**	$ 381	$ 345	**$ 95**	$ 66	$ 58	**$ 12,193**	$ 10,862	$ 9,421
$ 31	$ 18	$ 23	**$ 106**	$ 58	$ 44	**$ 23**	$ 23	$ 23	**$ 2,379**	$ 1,902	$ 1,707
$ 599	$ 702	$ 851	**$ 625**	$ 540	$ 537	**$ 134**	$ 105	$ 314	**$ 12,963**	$ 11,682	$ 10,292
–	–	–	**–**	–	–	**–**	–	–	**275**	264	341
$ 599	$ 702	$ 851	**$ 625**	$ 540	$ 537	**$ 134**	$ 105	$ 314	**$ 13,238**	$ 11,946	$ 10,633

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (CONTINUED)

Note 2

Nature of Operations and Organization

Husky Energy Inc. ("Husky" or "the Company") is a publicly traded, integrated energy and energy-related company headquartered in Calgary, Alberta, Canada.

Management has segmented the Company's business based on differences in products and services and management strategy and responsibility. The Company's business is conducted predominantly through three major business segments – upstream, midstream and refined products.

Upstream includes exploration for, development and production of crude oil, natural gas and natural gas liquids. The Company's upstream operations are located primarily in Western Canada, offshore Eastern Canada, offshore China and offshore Indonesia.

Midstream includes upgrading of heavy crude oil feedstock into synthetic crude oil (upgrading); marketing of the Company's and other producers' crude oil, natural gas, natural gas liquids, sulphur and petroleum coke; and pipeline transportation and processing of heavy crude oil, storage of crude oil, diluent and natural gas and cogeneration of electrical and thermal energy (infrastructure and marketing).

Refined products include refining of crude oil and marketing of refined petroleum products including gasoline, diesel, ethanol blended fuels, asphalt and ancillary products.

Note 3

Significant Accounting Policies

a) Principles of Consolidation and the Preparation of Financial Statements

These financial statements are prepared in accordance with Canadian generally accepted accounting principles ("GAAP") which, in the case of the Company, differ in certain respects from those in the United States. These differences are described in note 20, Reconciliation to Accounting Principles Generally Accepted in the United States.

The preparation of financial statements in conformity with Canadian GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reported period. Actual results could differ from these estimates.

The consolidated financial statements include the accounts of the Company and its subsidiaries.

Substantially all of the Company's upstream activities are conducted jointly with third parties and accordingly the accounts reflect the Company's proportionate share of the assets, liabilities, revenues, expenses and cash flow from these activities.

b) Cash and Cash Equivalents

Cash and cash equivalents consist of cash on hand and deposits with a maturity of less than three months at the time of purchase.

c) Inventory Valuation

Crude oil, natural gas, refined petroleum products and purchased sulphur inventories are valued at the lower of cost, on a first-in, first-out basis, or net realizable value. Materials and supplies are valued at the lower of average cost or net realizable value. Cost consists of raw material, labour, direct overhead and transportation. Intersegment profits are eliminated.

d) Property, Plant and Equipment

i) Oil and Gas

The Company employs the full cost method of accounting for oil and gas interests whereby all costs of acquisition, exploration for and development of oil and gas reserves are capitalized and accumulated within cost centres on a country-by-country basis. Such costs include land acquisition, geological and geophysical activity, drilling of productive and non-productive wells, carrying costs directly related to unproved properties and administrative costs directly related to exploration and development activities. Interest is capitalized on certain major capital projects based on the Company's long-term cost of borrowing.

The provision for depletion of oil and gas properties and depreciation of associated production facilities is calculated using the unit of production method, based on gross proved oil and gas reserves as estimated by the Company's engineers, for each cost centre. Depreciation of gas plants and certain other oil and gas facilities is provided using the straight-line method based on their estimated useful lives. Costs subject to depletion and depreciation include both the estimated costs required to develop proved undeveloped reserves and the associated addition to the asset retirement obligations. In the normal course of operations, retirements of oil and gas interests are accounted for by charging the asset cost, net of any proceeds, to accumulated depletion or depreciation. Gains or losses on the disposition of oil and gas properties are not recognized unless the gain or loss changes the depletion rate by 20 percent or more.

Costs of acquiring and evaluating significant unproved oil and gas interests are excluded from costs subject to depletion and depreciation until it is determined that proved oil and gas reserves are attributable to such interests or until impairment occurs. Costs of major development projects are excluded from costs subject to depletion and depreciation until proved developed reserves have been attributed to a portion of the property or the property is determined to be impaired.

Impairment losses are recognized when the carrying amount of a cost centre exceeds the sum of:

- the undiscounted cash flow expected to result from production from proved reserves;
- the costs of unproved properties, less impairment; and
- the costs of major development projects, less impairment.

The amount of impairment loss is determined to be the amount by which the carrying amount of the cost centre exceeds the sum of:

- the fair value of proved and probable reserves; and
- the cost, less impairment, of unproved properties that do not have probable reserves attributed to them.

ii) Other Plant and Equipment

Depreciation for substantially all other plant and equipment, except upgrading assets, is provided using the straight-line method based on estimated useful lives of assets which range from five to 25 years. Depreciation for upgrading assets is provided using the unit of production method, based on the plant's estimated productive life. Repairs and maintenance costs, other than major turnaround costs, are charged to earnings as incurred. Major turnaround costs are deferred to other assets when incurred and amortized over the estimated period of time to the next scheduled turnaround. At the time of disposition of plant and equipment, accounts are relieved of the asset values and accumulated depreciation and any resulting gain or loss is reflected in earnings.

iii) Asset Retirement Obligations

Effective January 1, 2004, the Company retroactively adopted CICA section 3110, "Asset Retirement Obligations". The new recommendations require that the recognition of the fair value of obligations associated with the retirement of tangible long-lived assets be recorded in the period that the asset is put into use, with a corresponding increase to the carrying value of the related asset. The obligations recognized are legal obligations. The liability is accreted over time for changes in the fair value of the liability through charges to accretion which is included in cost of sales and operating expenses. The liability will also be adjusted to reflect revisions to the previous estimates of the undiscounted obligation. The costs capitalized to the related assets are amortized to earnings in a manner consistent with the depletion, depreciation and amortization of the underlying asset. Retirement expenditures are charged to the accumulated liability as incurred.

e) Impairment or Disposal of Long-lived Assets

An impairment loss is recognized when the carrying value of a long-lived asset is not recoverable and exceeds its fair value. Testing for recoverability uses the undiscounted cash flows expected from the asset's use and disposition. To test for and measure impairment, long-lived assets are grouped at the lowest level for which identifiable cash flows are largely independent.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (CONTINUED)

A long-lived asset that meets the conditions as held for sale is measured at the lower of its carrying amount or fair value less costs to sell. Such assets are not amortized while they are classified as held for sale. The results of operations of a component of an entity that has been disposed of, or is classified as held for sale, are reported in discontinued operations if: i) the operations and cash flows of the component have been or will be eliminated as a result of the disposal transaction; and, ii) the entity will not have a significant continuing involvement in the operations of the component after the disposal transaction.

f) Goodwill

Goodwill is the excess of the purchase price paid over the fair value of net assets acquired. Goodwill is subject to impairment tests on an annual basis unless certain conditions are met. The Company tests impairment annually in the fourth quarter of each year. To assess impairment, the fair value of the reporting unit is compared with its carrying amount. If any potential impairment is indicated, then it is quantified by comparing the carrying value of goodwill to its fair value, based on the fair value of the assets and liabilities of the reporting unit. Impairment losses would be recognized in current period earnings, if indicated.

g) Derivative Financial Instruments

Derivative financial instruments are utilized by the Company to manage market risk against the volatility in commodity prices, foreign exchange rates and interest rate exposures. The Company's policy is not to utilize derivative financial instruments for speculative purposes. The Company may choose to designate derivative financial instruments as hedges.

When applicable, at the inception of the hedge, the Company formally documents the designation of the hedge, the risk management objectives, the hedging relationships between hedged items and hedging items and the method for testing the effectiveness of the hedge which must be reasonably assured over the term of the hedge. This process includes linking all derivatives to specific assets and liabilities on the balance sheet or to specific firm commitments or forecasted transactions. The Company formally assesses, both at the inception of the hedge and on an ongoing basis, whether the derivatives that are used in hedging transactions are highly effective in offsetting changes in fair values or cash flows of hedged items.

The Company may enter into commodity price contracts to hedge anticipated sales of oil and natural gas production to manage its exposure to price fluctuations. Gains and losses from these contracts are recognized in upstream oil and gas revenues as the related sales occur.

The Company may enter into commodity price contracts to offset fixed price contracts entered into with customers and suppliers in order to retain market prices while meeting customer or supplier pricing requirements. Gains and losses from these contracts are recognized in midstream revenues or cost of sales as the related sales or purchases occur.

The Company may enter into interest rate swap agreements to manage its fixed and floating interest rate mix on long-term debt. These swaps are designated as hedges of the underlying debt. Gains and losses from these contracts are recognized as an adjustment to the interest expense on the hedged debt instrument. The related amount payable or receivable from the counterparties is recorded as an adjustment to accrued interest.

The Company may enter into foreign exchange contracts to hedge its foreign currency exposures on U.S. dollar denominated long-term debt. Gains and losses on these instruments are accrued under other current, or non-current, assets or liabilities on the balance sheet and recognized in foreign exchange in the period to which they relate, offsetting the respective foreign exchange gains and losses recognized on the underlying foreign currency long-term debt. The forward premium or discount on the foreign exchange contract is amortized as an adjustment to interest expense over the term of the contract.

The Company may enter into foreign exchange forwards and foreign exchange collars to hedge anticipated U.S. dollar denominated oil and natural gas sales. Gains and losses on these instruments are recognized as an adjustment to upstream oil and gas revenues when the sale is recorded.

Realized and unrealized gains or losses associated with derivative financial instruments which have been terminated or cease to be effective as a hedge prior to maturity are deferred under current or non-current assets or liabilities on the balance sheet and recognized into income in the period in which the underlying hedged transaction is recognized in income. In the event that a designated hedged item is sold, extinguishes or matures prior to the termination of the related derivative financial instrument, any realized or unrealized gain or loss is recognized into earnings.

h) Employee Future Benefits

The Company provides a defined contribution pension plan and a post-retirement health and dental care plan to qualified employees. The Company also maintains a defined benefit pension plan for a small number of employees who did not choose to join the defined contribution pension plan in 1991. The cost of the pension benefits earned by employees in the defined contribution pension plan is paid and expensed when incurred. The cost of the benefits earned by employees in the post-retirement health and dental care plan and defined benefit pension plan is charged to earnings as services are rendered using the projected benefit method prorated on service. The cost of the post-retirement health and dental care plan and defined benefit pension plan reflects a number of assumptions that affect the expected future benefit payments. These assumptions include, but are not limited to, attrition, mortality, the rate of return on pension plan assets and salary escalations for the defined benefit pension plan and expected health care cost trends for the post-retirement health and dental care plan. The plan assets are valued at fair value for the purposes of calculating the expected return on plan assets.

Adjustments arising out of plan amendments, changes in assumptions and experience gains and losses are normally amortized over the expected remaining average service life of the employee group.

i) Future Income Taxes

The Company follows the liability method of accounting for income taxes. Future income tax assets and liabilities are recognized at expected tax rates in effect when temporary differences between the tax basis and the carrying value of the Company's assets and liabilities reverse. The effect of a change to the tax rate on the future tax assets and liabilities is recognized in earnings when substantively enacted.

j) Revenue Recognition

Revenues from the sale of crude oil, natural gas, natural gas liquids, synthetic crude oil, purchased commodities and refined petroleum products are recorded on a gross basis when title passes to an external party. Sales between the business segments of the Company are eliminated from sales and operating revenues and cost of sales. Revenues associated with the sale of transportation, processing and natural gas storage services are recognized when the services are provided. Effective January 1, 2004, certain transportation costs that were previously netted against revenue are now being recorded as cost of sales on a prospective basis.

k) Foreign Currency Translation

Results of foreign operations, all of which are considered financially and operationally integrated, are translated to Canadian dollars at the monthly average exchange rates for revenue and expenses, except for depreciation and depletion which are translated at the rate of exchange applicable to the related assets. Monetary assets and liabilities are translated at current exchange rates and nonmonetary assets and liabilities are translated using historical rates of exchange. Gains or losses resulting from these translation adjustments are included in earnings. Capital securities are adjusted to the current rate of exchange and included in retained earnings.

l) Stock-based Compensation

Effective January 1, 2004, the Company adopted CICA section 3870, "Stock-based Compensation and Other Stock-based Payments", retroactively without restatement of prior periods. In accordance with the Company's stock option plan, common share options may be granted to directors, officers and certain other employees. The recommendations require the Company to record a compensation expense over the vesting period based on the fair value of options granted.

Effective June 1, 2004, the Company amended its stock option plan to a tandem plan that provides the stock option holder with the right to exercise the stock option or surrender the option for a cash payment. A liability for expected cash settlements is accrued over the vesting period of the stock options based on the difference between the exercise price of the stock options and the market price of the Company's common shares. The liability is revalued to reflect changes in the market price of the Company's common shares and the net change is recognized in earnings. When stock options are surrendered for cash, the cash settlement paid reduces the outstanding liability. When stock options are exercised for common shares, consideration paid by the stock option holders and the previously recognized liability associated with the stock options are recorded as share capital. Accrued compensation for an option that is forfeited is adjusted to earnings by decreasing the compensation cost in the period of forfeiture.

m) Earnings per Share

Basic common shares outstanding are the weighted average number of common shares outstanding for each period. The calculation of basic earnings per common share is based on net earnings after deducting return and foreign exchange on capital securities, net of applicable income taxes, divided by the weighted average number of common shares outstanding.

Diluted common shares outstanding are calculated using the treasury stock method, which assumes that any proceeds received from in-the-money options would be used to buy back common shares at the average market price for the period. In addition, diluted common shares also include the effect of the potential exercise of any outstanding warrants. Shares potentially issuable on the settlement of the capital securities have not been included in the determination of diluted earnings per common share, as the Company has neither the obligation nor intention to settle amounts due through the issuance of shares.

n) Reclassification

Certain prior years' amounts have been reclassified to conform with current presentation.

Note 4 Accounts Receivable

	2004	*2003*	*2002*
Trade receivables	**$ 448**	$ 568	$ 530
Investment tax credit	**–**	48	45
Allowance for doubtful accounts	**(10)**	(12)	(11)
Other	**8**	14	8
	$ 446	$ 618	$ 572

Sale of Accounts Receivable

In December 2004, the Company increased the ceiling on its securitization program to sell, on a revolving basis, accounts receivable to a third party from $250 million to $350 million. As at December 31, 2004, $350 million (2003 – $250 million) in outstanding accounts receivable had been sold under the program. The agreement includes a program fee. The average effective rate for 2004 was approximately 2.6 percent (2003 – 2.8 percent).

The Company has retained the responsibility for servicing, administering and collecting accounts receivable sold. The servicing liability at December 31, 2004 was not significant.

Proceeds from revolving sales between the third party and the Company in 2004 totalled approximately $2.5 billion.

In 2002, the Company had an agreement to sell up to $200 million of net trade receivables on a continual basis. The agreement called for purchase discounts which were based on Canadian commercial paper rates. The average effective rate for 2002 was approximately 2.8 percent.

Note 5 Inventories

	2004	2003	2002
Crude oil and refined petroleum products	$ 159	$ 115	$ 160
Natural gas	100	69	50
Materials, supplies and other	15	14	17
	$ 274	$ 198	$ 227

Note 6 Property, Plant and Equipment

Refer to note 1, Segmented Financial Information, which presents the Company's property, plant and equipment by segment.

Costs of oil and gas properties, including major development projects, excluded from costs subject to depletion and depreciation at December 31 were as follows:

	2004	2003	2002
Canada	$ 2,399	$ 1,814	$ 1,318
International	129	54	37
	$ 2,528	$ 1,868	$ 1,355

The future cash flow used in the computation of the full cost ceiling test at December 31, 2004 was based on the following reference prices:

Western Canada	*2005*	*2006*	*2007*	*2008*	*2009*	*2010*	*Annual Increase Thereafter (percent)*
Light oil @ Edmonton *($/bbl)*	$ 52.60	$ 47.52	$ 42.56	$ 39.78	$ 38.44	$ 38.47	1.6
Medium oil @ Hardisty *($/bbl)*	47.08	42.55	37.96	35.52	34.24	34.27	1.7
Heavy oil @ Lloydminster *($/bbl)*	34.21	30.93	27.73	26.08	24.88	24.92	1.7
Alberta natural gas *($/mcf)*	7.25	6.87	6.39	5.91	5.69	5.69	1.6
Fixed price contract adjustment *($/mcf)*	(0.36)	(0.36)	(0.22)	(0.17)	(0.14)	(0.11)	

Note 7 Corporate Acquisitions

Effective July 15, 2004, the Company acquired all of the issued and outstanding shares of Temple Exploration Inc. ("Temple") for total cash consideration of $102 million.

Effective October 1, 2003, the Company acquired all of the issued and outstanding shares of Marathon Canada Limited and the Western Canadian assets of Marathon International Petroleum Canada, Ltd. ("Marathon Canada") for cash consideration of U.S. $611 million (Cdn $831 million).

The results of Temple and Marathon Canada are included in the consolidated financial statements of the Company from their acquisition dates.

The allocation of the aggregate purchase price based on the estimated fair values of the net assets of Temple and Marathon Canada on their acquisition dates was as follows:

	Temple	Marathon Canada
Net assets acquired		
Working capital (1)	$ (17)	$ (15)
Property, plant and equipment	138	1,008
Goodwill (2)	20	140
Asset retirement obligations	–	(38)
Future income taxes	(39)	(264)
	$ 102	$ 831

(1) Working capital of Marathon Canada acquired included cash of $22 million.

(2) Allocated to the Company's upstream segment and not deductible for income tax purposes. Refer to note 1, Segmented Financial Information.

In conjunction with the above acquisition of Marathon Canada, the Company sold certain of the Marathon Canada oil and gas properties to a third party for cash consideration of U.S. $320 million (Cdn $431 million).

Note 8 Cash Flows – Change in Non-cash Working Capital

a) Change in non-cash working capital was as follows:

	2004	2003	2002
Decrease (increase) in non-cash working capital			
Accounts receivable	$ **209**	$ (7)	$ (153)
Inventories	**(77)**	28	(2)
Prepaid expenses	**(12)**	(10)	1
Accounts payable and accrued liabilities	**323**	270	(11)
Change in non-cash working capital	**443**	281	(165)
Relating to:			
Financing activities	**337**	48	(9)
Investing activities	**(63)**	120	42
Operating activities	$ **169**	$ 113	$ (198)

b) Other cash flow information:

	2004	2003	2002
Cash taxes paid	$ **213**	$ 69	$ 20
Cash interest paid	$ **116**	$ 134	$ 139

Note 9 Bank Operating Loans

At December 31, 2004, the Company had short-term borrowing lines of credit with banks totalling $195 million (2003 and 2002 – $195 million). As at December 31, 2004, $49 million (2003 – $71 million; 2002 – nil) had been used for bank operating loans and $23 million (2003 – $18 million; 2002 – $12 million) had been used for letters of credit. Interest payable is based on Bankers' Acceptance, money market, or prime rates. During 2004, the weighted average interest rate on short-term borrowings was approximately 3.4 percent (2003 – 3.7 percent; 2002 – 2.9 percent).

Note 10 Accounts Payable and Accrued Liabilities

		2004		2003		2002
Trade payables	$	110	$	58	$	87
Accrued liabilities		751		794		562
Dividend payable		280		42		38
Commodity contract settlements		50		8		–
Stock-based compensation		49		–		–
Current income taxes		119		117		51
Other		130		107		56
	$	1,489	$	1,126	$	794

Note 11 Long-term Debt

		Cdn $ Amount			U.S. $ Amount		
	Maturity	2004	2003	2002	2004	2003	2002
Long-term debt							
Syndicated credit facility	2007	$ 70	$ –	$ –	$ –	$ –	$ –
Bilateral credit facilities	2006-7	40	–	–	–	–	–
6.875% notes		–	–	237	–	–	150
7.125% notes	2006	181	194	237	150	150	150
6.25% notes	2012	481	517	632	400	400	400
7.55% debentures	2016	241	258	316	200	200	200
6.15% notes	2019	361	–	–	300	–	–
Private placement notes	2005	18	41	107	15	32	68
8.45% senior secured bonds	2005-12	140	188	256	117	145	162
Medium-term notes	2007-9	300	500	600	–	–	–
Total long-term debt		1,832	1,698	2,385	$ 1,182	$ 927	$ 1,130
Amount due within one year		(56)	(259)	(421)			
		$ 1,776	$ 1,439	$ 1,964			

Required debt repayments for the following periods are:

	Amount
2005	$ 56
2006	226
2007	219
2008	19
2009	214
Thereafter	1,098
	$ 1,832

Interest – net for the years ended December 31 was as follows:

	2004	2003	2002
Long-term debt	$ 106	$ 129	$ 128
Short-term debt	3	2	3
	109	131	131
Amount capitalized	(75)	(52)	(26)
	34	79	105
Interest income	(1)	(6)	(1)
	$ 33	$ 73	$ 104

Foreign exchange for the years ended December 31 was as follows:

	2004	2003	2002
Gain on translation of U.S. dollar denominated long-term debt	$ (129)	$ (315)	$ –
Cross currency swaps	27	73	–
Other losses	3	27	13
	$ (99)	$ (215)	$ 13

As at December 31, 2004, other assets included $22 million (2003 – $19 million; 2002 – $23 million) of deferred debt issue costs.

Credit Facilities

The revolving syndicated credit facility allows the Company to borrow up to $950 million in either Canadian or U.S. currency from a group of banks on an unsecured basis. The facility is structured as a one-year committed revolving credit facility, extendible annually. In the event that the lenders do not consent to such extension, the revolving credit facility will convert to a two-year non-revolving amortizing term loan. Interest rates vary based on Canadian prime, Bankers' Acceptance, U.S. LIBOR or U.S. base rate, depending on the borrowing option selected, credit ratings assigned by certain credit rating agencies to the Company's rated senior unsecured debt and whether the Company borrows under the revolving or non-revolving condition.

The Company's $150 million revolving bilateral credit facilities have substantially the same terms as the syndicated credit facility.

Notes and Debentures

The 7.125 percent notes and the 7.55 percent debentures represent unsecured securities issued under a trust indenture dated October 31, 1996. These securities mature in 2006 and 2016, respectively. The 7.125 percent notes are not redeemable prior to maturity. Interest is payable semi-annually.

The 6.25 percent and the 6.15 percent notes represent unsecured securities issued under a trust indenture dated June 14, 2002. Interest is payable semi-annually.

On August 12, 2004, the Company filed a base shelf prospectus with securities regulatory authorities in Canada and the United States. The prospectus permits Husky to offer for sale, from time to time, up to U.S. $1 billion of debt securities during the 25 months from August 12, 2004. No notes have been issued under the base shelf prospectus as of December 31, 2004.

The private placement notes represent unsecured securities under a master shelf agreement dated January 31, 2001 and have an interest rate of 6.89 percent. Interest is payable quarterly.

The 8.45 percent senior secured bonds represent securities issued by a subsidiary under a trust indenture dated July 20, 1999. These securities amortize semi-annually. Such securities were issued in connection with the financing of the Company's share of the costs for the exploration and development of the Terra Nova oil field located off the East Coast of Canada. Interest is payable semi-annually. The Company has the option of delaying the repayment schedule by one year. The Company, through a wholly owned partnership, owns 12.51 percent of the Terra Nova oil field and associated facilities. The repayment of the securities is contracted to be made solely from revenue from the Terra Nova oil field. There is also a charge created by the partnership on its interest in the assets of the Terra Nova oil field and associated facilities in favour of the security holders. Certain related financial obligations require collateral of letters of credit and/or cash equivalents. As at December 31, 2004, letters of credit totalling $54 million (2003 – $54 million; 2002 – $38 million) were outstanding.

The medium-term notes Series B represent unsecured securities issued under a trust indenture dated February 3, 1997 and the Series E notes represent unsecured securities issued under a trust indenture dated May 4, 1999. The amounts, rates and maturities are as follows:

Issue	*Amount*	*Interest Rate*	*Maturity Date*
Series B	$ 100	6.85%	February 2007
Series E	200	6.95%	July 2009
	$ 300		

Interest is payable semi-annually on all series.

The notes and debentures disclosed above are redeemable (unless otherwise stated) at the option of the Company, at any time, at a redemption price equal to the greater of the par value of the securities and the sum of the present values of the remaining scheduled payments discounted at a rate calculated using a comparable U.S. Treasury Bond rate (for U.S. dollar denominated securities) or Government of Canada Bond rate (for Canadian dollar denominated securities) plus an applicable spread.

Note 12 Other Long-term Liabilities

	2004	*2003*	*2002*
Asset retirement obligations	$ 509	$ 432	$ 286
Cross currency swaps	68	41	–
Interest rate swaps	18	26	–
Employee future benefits	23	20	17
Stock-based compensation	14	–	–
Other	–	–	1
	$ 632	$ 519	$ 304

Asset Retirement Obligations

The Company adopted the new recommendations for the recognition of the obligations to retire long-lived tangible assets. The change was effective January 1, 2004 and the revision was applied retroactively.

The impact of the retroactive revision was as follows:

	2003			2002		
	As Reported [(1)]	*Change*	*As Restated*	*As Reported* [(1)]	*Change*	*As Restated*
Consolidated Balance Sheets						
Assets						
Property, plant and equipment, net	$ 10,698	$ 164	$ 10,862	$ 9,363	$ 58	$ 9,421
Liabilities and Shareholders' Equity						
Other long-term liabilities	390	129	519	266	38	304
Future income taxes	2,608	13	2,621	2,003	11	2,014
Retained earnings	2,134	22	2,156	1,357	9	1,366
Consolidated Statements of Earnings						
Cost of sales and operating expenses	$ 4,825	$ 22	$ 4,847	$ 4,009	$ 17	$ 4,026
Depletion, depreciation and amortization	1,058	(37)	1,021	939	(31)	908
Future income taxes	327	2	329	354	4	358
Net earnings	1,321	13	1,334	804	10	814
Earnings per share						
Basic	$ 3.23	$ 0.03	$ 3.26	$ 1.88	$ 0.03	$ 1.91
Diluted	$ 3.22	$ 0.03	$ 3.25	$ 1.88	$ 0.02	$ 1.90

(1) Certain amounts have been reclassified to conform with current presentation.

At December 31, 2004, the estimated total undiscounted amount required to settle the asset retirement obligations was $2.9 billion. These obligations will be settled based on the useful lives of the underlying assets, which currently extend up to 50 years into the future. This amount has been discounted using credit adjusted risk free rates ranging from 6.2 percent to 6.4 percent.

Changes to the asset retirement obligations were as follows:

	2004	2003	2002
Asset retirement obligations, beginning of year	$ 432	$ 286	$ 247
Liabilities incurred	13	158	38
Liabilities settled	(40)	(34)	(16)
Revisions	77	–	–
Accretion	27	22	17
Asset retirement obligations, end of year	$ 509	$ 432	$ 286

Note 13

Income Taxes

The combined provision for income taxes in the Consolidated Statements of Earnings and Retained Earnings reflects an effective tax rate which differs from the expected statutory tax rate. Differences for the years ended December 31 were accounted for as follows:

	2004	2003	2002
Earnings before income taxes			
Canadian	$ 1,171	$ 1,587	$ 1,084
Foreign jurisdictions	240	223	154
	1,411	1,810	1,238
Statutory income tax rate *(percent)*	39.3	40.2	41.6
Expected income tax	555	728	515
Effect on income tax of:			
Royalties, lease rentals and mineral taxes payable to the crown	153	175	159
Resource allowance on Canadian production income	(156)	(183)	(212)
Rate benefit on partnership earnings	(42)	(23)	–
Change in statutory tax rate	(40)	(161)	(31)
Return on capital securities	(6)	2	(11)
Non-deductible capital taxes	20	22	18
Gains and losses on foreign exchange	(20)	(45)	–
Foreign jurisdictions	(13)	(16)	(13)
Other – net	(52)	(21)	(12)
	$ 399	$ 478	$ 413
Charged (credited) to:			
Income tax expense	$ 405	$ 476	$ 424
Retained earnings	(6)	2	(11)
	$ 399	$ 478	$ 413

The future income tax liability at December 31 comprised the tax effect of temporary differences as follows:

	2004	2003	2002
Future tax liabilities			
Property, plant and equipment	$ 2,949	$ 2,826	$ 2,226
Foreign exchange gains taxable on realization	56	32	–
Other temporary differences	5	2	30
	3,010	2,860	2,256
Future tax assets			
Asset retirement obligations	180	160	121
Loss carry forwards	11	2	7
Foreign exchange losses deductible on realization	–	–	28
Provincial royalty rebates	14	52	48
Other temporary differences	47	25	38
	252	239	242
	$ 2,758	$ 2,621	$ 2,014

Note 14 Commitments and Contingencies

Certain former owners of interests in the upgrading assets retained a 20-year upside financial interest expiring in 2014 which requires payments to them when the average differential between heavy crude oil feedstock and synthetic crude oil exceeds $6.50 per barrel. The calculation is based on a two-year rolling average of the differential. During 2004, the Company capitalized $27 million (2003 – $10 million; 2002 – $23 million) of payments under this arrangement.

At December 31, 2004, the Company had commitments for non-cancellable operating leases and other long-term agreements that require the following minimum future payments:

	2005	*2006*	*2007*	*2008*	*2009*	*After 2009*	*Total*
Operating leases	$ 68	$ 76	$ 76	$ 78	$ 73	$ 183	$ 554
Firm transportation agreements	213	202	173	143	119	211	1,061
Unconditional purchase obligations	593	428	256	63	24	117	1,481
Lease rentals	44	44	44	44	44	110	330
Exploration work agreements	27	5	10	–	–	8	50
Engineering and construction commitments	572	241	142	12	–	–	967
	$ 1,517	$ 996	$ 701	$ 340	$ 260	$ 629	$ 4,443

The Company is involved in various claims and litigation arising in the normal course of business. While the outcome of these matters is uncertain and there can be no assurance that such matters will be resolved in the Company's favour, the Company does not currently believe that the outcome of adverse decisions in any pending or threatened proceedings related to these and other matters or any amount which it may be required to pay by reason thereof would have a material adverse impact on its financial position, results of operations or liquidity.

The Company has income tax filings that are subject to audit and potential reassessment. The findings may impact the tax liability of the Company. The final results are not reasonably determinable at this time and management believes that it has adequately provided for current and future income taxes.

Note 15 Capital Securities

The Company issued U.S. $225 million unsecured capital securities under an indenture dated August 10, 1998. Such securities rank junior to all senior debt and other financial debt of the Company. They yield an annual return of 8.9 percent, payable semi-annually until August 15, 2008 and mature in 2028. The capital securities are redeemable, in whole or in part, by the Company at any time prior to August 15, 2008 at a redemption price equal to the greater of the par value of the securities and the sum of the present values of the remaining scheduled payments discounted at a rate calculated using a comparable U.S. Treasury Bond rate plus an applicable spread. They are redeemable at par, in whole but not in part, by the Company on or after August 15, 2008. If not redeemed in whole, commencing on August 15, 2008, the annual return changes to a floating rate equal to U.S. LIBOR plus 5.50 percent payable semi-annually. The Company has the right at any time prior to maturity to defer payment of the return on the securities. Since the Company also has the unrestricted ability to settle its deferred return, principal and redemption obligations through the issuance of common or preferred shares, the principal amount of the capital securities, net of issue costs, has been classified as equity. The return and foreign exchange on capital securities, net of income taxes, are classified as a distribution of equity.

The amounts disclosed as capital securities and accrued return in shareholders' equity at December 31 were as follows:

	2004	2003	2002
Capital securities – U.S. $225	$ 271	$ 291	$ 355
Unamortized costs of issue	(2)	(3)	(3)
Accrued return	9	10	12
	$ 278	$ 298	$ 364

In November 2003, the Accounting Standards Board revised recommendations in CICA section 3860, "Financial Instruments – Disclosure and Presentation", on the classification of obligations that must or could be settled with an entity's own equity instruments. The new recommendations will be effective January 1, 2005 and will result in the Company's capital securities being classified as liabilities instead of equity. The accrued return on the capital securities and the issue costs will be classified outside of shareholders' equity. The return on the capital securities will be a charge to earnings. The revision will be applied retroactively effective January 1, 2005 and will result in the following changes to the Company's financial statements:

	2004			2003			2002		
	As Reported	*Change*	*Pro Forma*	*As Reported*	*Change*	*Pro Forma*	*As Reported*	*Change*	*Pro Forma*
Consolidated Balance Sheets									
Assets									
Other assets	$ 106	$ 2	$ 108	$ 112	$ 3	$ 115	$ 84	$ 3	$ 87
Liabilities and Shareholders' Equity									
Accounts payable and accrued liabilities	1,489	9	1,498	1,126	10	1,136	794	12	806
Long-term debt	1,776	271	2,047	1,439	291	1,730	1,964	355	2,319
Capital securities and accrued return	278	(278)	–	298	(298)	–	364	(364)	–
Consolidated Statements of Earnings									
Interest – net	$ 33	$ 27	$ 60	$ 73	$ 29	$ 102	$ 104	$ 32	$ 136
Foreign exchange	(99)	(21)	(120)	(215)	(67)	(282)	13	(3)	10
Future income taxes	103	(6)	97	329	2	331	358	(11)	347
Net earnings	1,006	–	1,006	1,334	36	1,370	814	(18)	796

Effective January 1, 2005, the Company will be required to include the capital securities in the determination of diluted earnings per common share.

Note 16

Share Capital

The Company's authorized share capital is as follows:

Common shares – an unlimited number of no par value.

Preferred shares – an unlimited number of no par value, none outstanding.

Common Shares

Changes to issued share capital were as follows:

	Number of Shares	*Amount*
January 1, 2002	416,878,093	$ 3,397
Options and warrants exercised	995,508	9
December 31, 2002	417,873,601	3,406
Options and warrants exercised	4,302,141	51
December 31, 2003	422,175,742	3,457
Stock-based compensation – adoption	–	23
Options and warrants exercised	1,560,672	26
December 31, 2004	**423,736,414**	**$ 3,506**

Stock Options

At December 31, 2004, 23.2 million common shares were reserved for issuance under the Company stock option plan. As described in note 3 l), on June 1, 2004, the Company modified its stock option plan to a tandem plan that provides the stock option holder with the right to exercise the option or surrender the option for a cash payment. The exercise price of the option is equal to the average market price of the Company's common shares during the five trading days prior to the date of the award. When the option is surrendered for cash, the cash payment is the difference between the average market price of the Company's common shares on the trading day prior to the surrender date and the exercise price of the option. Under the stock option plan the options awarded have a maximum term of five years and vest over three years on the basis of one-third per year.

A downward adjustment of $0.48 was made to the exercise price of all outstanding stock options effective November 29, 2004, pursuant to the terms of the stock option plan under which the options were issued as a result of the special $0.54 per share dividend that was declared in November 2004. A similar downward adjustment of $0.82 was made to the exercise price of all outstanding stock options effective September 3, 2003, as a result of the special $1.00 per share dividend that was declared in July 2003.

The following options to purchase common shares have been awarded to directors, officers and certain other employees:

	Number of Options (thousands)	*Weighted Average Exercise Prices*	*Weighted Average Contractual Life (years)*	*Options Exercisable (thousands)*
December 31, 2001	8,602	$ 13.78	4	2,853
Granted	568	$ 16.11	5	
Exercised for common shares	(608)	$ 13.63	2	
Forfeited	(642)	$ 14.37	3	
December 31, 2002	7,920	$ 13.91	3	4,822
Granted	591	$ 19.17	5	
Exercised for common shares	(3,789)	$ 13.45	2	
Forfeited	(125)	$ 14.71	2	
December 31, 2003	4,597	$ 13.88	2	3,564
Granted	8,200	$ 25.10	4	
Exercised for common shares	(1,350)	$ 13.11	1	
Surrendered for cash	(1,269)	$ 13.32	1	
Forfeited	(214)	$ 22.73	4	
December 31, 2004	**9,964**	**$ 22.61**	**4**	**1,417**

As at December 31, 2004	*Outstanding Options*			*Options Exercisable*	
Range of Exercise Price	*Number of Options (thousands)*	*Weighted Average Exercise Prices*	*Weighted Average Contractual Life (years)*	*Number of Options (thousands)*	*Weighted Average Exercise Prices*
\$9.86 – \$14.99	1,443	$ 12.75	1	1,320	$ 12.57
\$15.00 – \$23.99	475	$ 18.40	3	97	$ 19.39
\$24.00 – \$32.14	8,046	$ 24.62	4	–	$ –
	9,964	$ 22.61	4	1,417	$ 13.04

Warrants

In 2000, the Company granted 1.4 million Renaissance Energy Ltd. ("Renaissance") replacement options to purchase common shares of Husky in exchange for certain share purchase options to purchase common shares of Renaissance previously held by employees of Renaissance. The former shareholders of Husky Oil Limited were also granted warrants to acquire, for no additional consideration, 1.86 common shares of the Company for each common share issued on the exercise of a Renaissance replacement option. The warrants are exercisable only if and when the Renaissance replacement options are exercised and provide for the issue of a maximum of 2.5 million common shares. During 2004, 113,600 warrants were exercised (2003 – 276,500; 2002 – 208,500). As at December 31, 2004, there were 51,068 common shares remaining which could potentially be issued as a result of the exercise of these warrants. The Renaissance replacement options had a weighted average contractual life of 0.2 years at December 31, 2004.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (CONTINUED)

Earnings per Common Share

	2004	2003	2002
Net earnings	**$ 1,006**	$ 1,334	$ 814
Return and foreign exchange on capital securities (net of related taxes)	**–**	36	(18)
Net earnings available to common shareholders	**$ 1,006**	$ 1,370	$ 796
Weighted average number of common shares outstanding			
Basic *(millions)*	**423.4**	419.5	417.4
Effect of dilutive stock options and warrants	**2.3**	2.0	1.9
Weighted average number of common shares outstanding			
Diluted *(millions)*	**425.7**	421.5	419.3
Earnings per share			
Basic	**$ 2.37**	$ 3.26	$ 1.91
Diluted	**$ 2.36**	$ 3.25	$ 1.90

Stock-based Compensation

As described in note 3 l), beginning January 1, 2004, stock-based compensation is being recognized in earnings. This change was adopted retroactively without restatement of prior periods and resulted in a decrease to retained earnings of $44 million, an increase to contributed surplus of $21 million and an increase to share capital of $23 million on January 1, 2004. If the Company had applied the fair value method retroactively with restatement of prior periods for all options granted, the Company's net earnings and earnings per share for the years ended December 31, 2003 and 2002 would have been as follows:

	2003	2002
Compensation cost – all options granted (1)	$ 14	$ 13
Net earnings available to common shareholders		
As reported	$ 1,370	$ 796
As restated	$ 1,356	$ 783
Weighted average number of common shares outstanding *(millions)*		
Basic	419.5	417.4
Diluted	421.5	419.3
Basic earnings per share		
As reported	$ 3.26	$ 1.91
As restated	$ 3.23	$ 1.88
Diluted earnings per share		
As reported	$ 3.25	$ 1.90
As restated	$ 3.22	$ 1.87

(1) Includes options modified.

As described in note 3 l), effective June 1, 2004, the Company modified the stock option plan to a tandem plan, resulting in an increase to current liabilities of $34 million, a decrease to contributed surplus of $16 million and an increase to stock-based compensation expense of $18 million. Prior to the modification, the fair values of all common share options granted were estimated on the date of grant using the Black-Scholes option-pricing model. The grant date fair values and assumptions used prior to June 1, 2004 were:

	2004	*2003*	*2002*
Weighted average fair value per option	**$ 5.67**	$ 4.00	$ 5.19
Risk-free interest rate *(percent)*	**3.1**	3.9	3.6
Volatility *(percent)*	**21**	23	43
Expected life *(years)*	**5**	5	5
Expected annual dividend per share	**$ 0.44**	$ 0.36	$ 0.36

As a result of the downward adjustment of $0.82 to the exercise price of all outstanding options effective September 3, 2003, the fair values of all common share options granted prior to that date were revalued on September 3, 2003 using the Black-Scholes option-pricing model. The weighted average fair value of outstanding stock options as at September 3, 2003 and the assumptions used are noted below:

Weighted average fair value per option	$ 7.14
Risk-free interest rate *(percent)*	2.8
Volatility *(percent)*	20
Expected life *(years)*	2.3
Expected annual dividend per share	$ 0.40

Dividends

During 2004, the Company declared dividends of $1.00 per common share (2003 – $1.38 per common share; 2002 – $0.36 per common share), including a special dividend of $0.54 per common share (2003 – $1.00 per common share).

Contributed Surplus

Changes to contributed surplus were as follows:

	2004
January 1, 2004	**$ –**
Stock-based compensation – adoption	**21**
Stock-based compensation cost	**1**
Stock options exercised	**(6)**
Modification of stock option plan – June 1, 2004	**(16)**
December 31, 2004	**$ –**

Note 17 Employee Future Benefits

The Company currently provides a defined contribution pension plan for all qualified employees. The Company also maintains a defined benefit pension plan, which is closed to new entrants, and all current participants are vested. The Company also provides certain health and dental coverage to its retirees which is accrued over the expected average remaining service life of the employees.

Weighted average long-term assumptions are based on independent historical and projected references and are noted below:

	2004	2003	2002
Discount rate *(percent)*	**6.0**	6.0	6.3
Long-term rate of increase in compensation levels *(percent)*	**5.0**	5.0	5.0
Long-term rate of return on plan assets *(percent)*	**8.0**	8.0	8.0

The discount rate used at the end of 2004 to determine the accrued benefit obligation was 5.75 percent.

The long-term rate of return on the assets was determined based on management's best estimate and the historical rates of return, adjusted periodically. The rate at the end of 2004 was 7.5 percent.

The average health care cost trend used was eight percent, which is reduced by 0.50 percent until 2009. The average dental care cost trend used was four percent, which remains constant.

Defined Benefit Pension Plan

The status of the defined benefit pension plan at December 31 was as follows:

Benefit Obligation	2004	2003	2002
Benefit obligation, beginning of year	**$ 118**	$ 108	$ 95
Current service cost	**2**	2	2
Interest cost	**7**	7	7
Benefits paid	**(6)**	(6)	(6)
Actuarial losses	**3**	7	10
Benefit obligation, end of year	**$ 124**	$ 118	$ 108

Fair Value of Plan Assets	2004	2003	2002
Fair value of plan assets, beginning of year	**$ 85**	$ 77	$ 85
Contributions	**10**	8	2
Benefits paid	**(6)**	(6)	(6)
Expected return on plan assets	**7**	6	7
Gain (loss) on plan assets	**1**	2	(11)
Foreign exchange losses	**(1)**	(2)	–
Fair value of plan assets, end of year	**$ 96**	$ 85	$ 77

Funded Status of Plan	2004	2003	2002
Fair value of plan assets	**$ 96**	$ 85	$ 77
Benefit obligation	**(124)**	(118)	(108)
Excess obligation	**(28)**	(33)	(31)
Unrecognized past service costs	**1**	1	1
Unrecognized losses	**32**	32	27
Accrued benefit asset (liability)	**$ 5**	$ –	$ (3)

Husky, under the purview of its Board of Directors, adheres to a Statement of Investment Policies and Procedures (the "Policy") that conforms to applicable government regulation. The assets are allocated in accordance with the long-term nature of the obligation and comprise a balanced investment based on interest rate and inflation sensitivities. The Policy explicitly prescribes diversification parameters for all classes of investment.

The date of the last actuarial valuation for the Company was December 31, 2002 and the next scheduled actuarial valuation will take place January 1, 2005.

The composition of the defined benefit pension plan assets was as follows:

	2004	2003	2002
U.S. common equities	15%	15%	15%
Canadian common equities	25	28	29
International equity mutual funds	11	10	7
Canadian equity mutual funds	–	2	2
Canadian government bonds	25	29	26
Canadian corporate bonds	16	12	14
Cash and receivables	8	4	7
Total	100%	100%	100%

During 2004, Husky contributed $10 million to the defined benefit pension plan assets, $8 million of which was in respect of additional contributions as a result of the plan's deficiency. Husky currently plans to contribute a similar amount in 2005.

The Company amortizes the portion of the unrecognized actuarial gains or losses that exceed 10 percent of the greater of the accrued benefit obligation or the market-related value of pension plan assets. The market-related value of pension plan assets is the fair value of the assets. The gains or losses that are in excess of 10 percent are amortized over the expected future years of service, which is currently eight years.

The past service costs are amortized over the expected future years of service.

Post-retirement Health and Dental Care Plan

The status of the post-retirement health and dental care plan at December 31 was as follows:

Benefit Obligation	2004	2003	2002
Benefit obligation, beginning of year	$ 23	$ 21	$ 16
Current service cost	2	2	1
Interest cost	1	1	1
Benefits paid	(1)	(1)	–
Actuarial losses	–	–	3
Benefit obligation, end of year	$ 25	$ 23	$ 21

Funded Status of Plan	2004	2003	2002
Benefit obligation	$ (25)	$ (23)	$ (21)
Unrecognized losses	2	3	4
Accrued benefit liability	$ (23)	$ (20)	$ (17)

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (CONTINUED)

The assumed health care cost trend can have a significant effect on the amounts reported for Husky's post-retirement health and dental care plan. A one percent increase and decrease in the assumed trend rate would have the following effect:

	1% Increase	*1% Decrease*
Effect on total service and interest cost components	$ 1	$ –
Effect on post-retirement benefit obligation	$ 4	$ (3)

Pension Expense and Post-retirement Health and Dental Care Expense

The expenses for the years ended December 31 were as follows:

Pension Expense	*2004*	*2003*	*2002*
Defined benefit pension plan			
Employer current service cost	$ 2	$ 2	$ 2
Interest cost	7	7	7
Expected return on plan assets	(7)	(6)	(7)
Amortization of net actuarial losses	2	2	–
	4	5	2
Defined contribution pension plan	12	11	10
Total expense	$ 16	$ 16	$ 12

Post-retirement Health and Dental Care Expense	*2004*	*2003*	*2002*
Employer current service cost	$ 2	$ 2	$ 1
Interest cost	1	1	1
Total expense	$ 3	$ 3	$ 2

Future Benefit Payments

The following table discloses the current estimate of future benefit payments:

	Defined Benefit Pension Plan	*Post-retirement Health and Dental Care Plan*
2005	$ 7	$ 1
2006	7	1
2007	7	1
2008	7	1
2009	8	1
2010 – 2014	45	6

Note 18 Related Party Transactions

Husky, in the ordinary course of business, was party to a lease agreement with Western Canadian Place Ltd. The terms of the lease provided for the lease of office space at Western Canadian Place, management services and operating costs at commercial rates. Effective July 13, 2004, Western Canadian Place Ltd. sold Western Canadian Place to an unrelated party. Western Canadian Place Ltd. is indirectly controlled by Husky's principal shareholders. Prior to the sale, Husky paid approximately $10 million for office space in Western Canadian Place during 2004.

Note 19

Financial Instruments and Risk Management

Carrying Values and Estimated Fair Values of Financial Assets and Liabilities

The carrying value of cash and cash equivalents, accounts receivable, bank operating loans, accounts payable and accrued liabilities approximates their fair value due to the short-term maturity of these instruments.

The fair value of the long-term debt is the present value of future cash flows associated with the debt. Market information such as treasury rates and credit spreads is used to determine the appropriate discount rates. The estimated fair value of the long-term debt at December 31 was as follows:

	2004		2003		2002	
	Carrying Value	*Fair Value*	*Carrying Value*	*Fair Value*	*Carrying Value*	*Fair Value*
Long-term debt	$ 1,832	$ 1,991	$ 1,698	$ 1,869	$ 2,385	$ 2,579

Unrecognized Gains (Losses) on Derivative Instruments

	2004	2003	2002
Commodity price risk management			
Natural gas	$ (9)	$ (8)	$ (4)
Crude oil	–	(109)	6
Power consumption	(1)	2	–
Interest rate risk management			
Interest rate swaps	52	31	86
Foreign currency risk management			
Foreign exchange contracts	(30)	(19)	(7)
Foreign exchange forwards	–	15	(5)

Commodity Price Risk Management

Natural Gas Production

During 2004 the impact of the 2004 hedge program was a gain of $8 million (2003 – gain of $24 million).

At December 31, 2004, the Company had hedged 7.5 mmcf of natural gas per day at NYMEX for 2005 at an average price of U.S. $1.92 per mcf. During 2004 the impact was a loss of $9 million (2003 – loss of $8 million; 2002 – insignificant).

Crude Oil Production

The impact of the 2004 hedge program was a loss of $560 million (2003 – loss of $36 million; 2002 – gain of $5 million).

Power Consumption

At December 31, 2004, the Company had hedged power consumption of 197,100 MWh from January to December 2005 at an average fixed price of $49.94 per MWh and 65,160 MWh from January to June 2005 at an average fixed price of $48.00 per MWh. The impact of the 2004 hedge program was a gain of $3 million.

Natural Gas Contracts

The Company has a portfolio of fixed and basis price offsetting physical forward purchase and sale natural gas contracts relating to marketing of other producers' natural gas. The objective of these contracts is to "lock in" a positive spread between the physical purchase and sale contract prices. At December 31, 2004, the Company had the following offsetting physical purchase and sale contracts:

	Volumes (mmcf)	*Unrecognized Gain (Loss)*
Physical purchase contracts	14,276	$ (2)
Physical sale contracts	(14,276)	$ 3

Interest Rate Risk Management

The majority of the Company's long-term debt has fixed interest rates and various maturities. The Company periodically uses interest rate swaps to manage its financing costs. At December 31, 2004, the Company had entered into interest rate swap arrangements whereby the fixed interest rate coupon on certain debt was swapped to floating rates with the following terms:

Debt	*Amount*	*Swap Maturity*	*Swap Rate (percent)*
6.95% medium-term notes	$200	July 14, 2009	CDOR + 175 bps
7.55% debentures	U.S. $200	November 15, 2011	U.S. LIBOR + 194 bps
6.15% notes	U.S. $300	June 15, 2019	U.S. LIBOR + 63 bps

During 2004 the Company realized a gain of $22 million (2003 – gain of $17 million; 2002 – gain of $29 million) from interest rate risk management activities.

In 2003, the Company unwound three interest rate swaps for proceeds of $44 million. The proceeds have been deferred and are being amortized to income over the remaining term of the underlying debt.

Foreign Currency Risk Management

The Company manages its exposure to foreign exchange rate fluctuations by balancing the U.S. dollar denominated cash flows with U.S. dollar denominated borrowings and other financial instruments. Husky utilizes spot and forward sales to convert cash flows to or from U.S. or Canadian currency.

At December 31, 2004, the Company had the following cross currency debt swaps:

Debt	*Swap Amount*	*Canadian Equivalent*	*Swap Maturity*	*Interest Rate (percent)*
7.125% notes	U.S. $150	$218	November 15, 2006	8.74
6.25% notes	U.S. $150	$212	June 15, 2012	7.41

The Company hedged U.S. dollar revenues for various amounts and maturities through 2005 using foreign exchange forwards. On November 10, 2004, the Company unwound its long-dated forwards totalling U.S. $36 million, which resulted in a gain of $8 million that has been deferred and will be recognized into income on the dates that the underlying hedged transactions are to take place.

During 2004 the Company recognized a loss of $13 million (2003 – loss of $56 million; 2002 – loss of $11 million) from foreign currency risk management activities.

Credit Risk

Accounts receivable are predominantly with customers in the energy industry and are subject to normal industry credit risks.

In addition, the Company is exposed to credit related losses in the event of non-performance by counterparties to its derivative financial instruments. The Company primarily deals with major financial institutions and investment grade rated entities to mitigate these risks.

Husky did not have any customers that constituted more than five percent of total sales and operating revenues during 2004.

Note 20 Reconciliation to Accounting Principles Generally Accepted in the United States

The Company's consolidated financial statements have been prepared in accordance with GAAP in Canada, which differ in some respects from those in the United States. Any differences in accounting principles as they pertain to the accompanying consolidated financial statements were insignificant except as described below:

Consolidated Statements of Earnings

	2004	2003	2002
Net earnings under Canadian GAAP	**$ 1,006**	$ 1,334	$ 814
Adjustments:			
Full cost accounting *(a)*	**37**	80	88
Related income taxes	**(13)**	(30)	(37)
Foreign exchange on capital securities *(b)*	**21**	67	3
Related income taxes	**(3)**	(12)	(1)
Return on capital securities *(b)*	**(27)**	(29)	(32)
Related income taxes	**9**	11	11
Derivatives and hedging *(c)*	**–**	(1)	22
Related income taxes	**–**	1	(9)
Energy trading contracts *(c)*	**(1)**	(15)	(2)
Related income taxes	**–**	6	1
Asset retirement obligations *(d)*	**–**	–	(14)
Related income taxes	**–**	–	4
Stock-based compensation *(e)*	**2**	(46)	–
Accounting for income taxes *(f)*	**–**	–	(37)
Earnings before cumulative effect of change in accounting principle under U.S. GAAP	**1,031**	1,366	811
Cumulative effect of change in accounting principle, net of tax *(d)*	**–**	9	–
Net earnings under U.S. GAAP	**$ 1,031**	$ 1,375	$ 811
Weighted average number of common shares outstanding under U.S. GAAP *(millions)*			
Basic	**423.4**	419.5	417.4
Diluted	**425.7**	421.5	419.3
Earnings per share before cumulative effect of change in accounting principle under U.S. GAAP			
Basic	**$ 2.44**	$ 3.26	$ 1.94
Diluted	**$ 2.42**	$ 3.24	$ 1.93
Earnings per share under U.S. GAAP			
Basic	**$ 2.44**	$ 3.28	$ 1.94
Diluted	**$ 2.42**	$ 3.26	$ 1.93

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (CONTINUED)

Condensed Consolidated Balance Sheets

	2004		2003		2002	
	Canadian GAAP	U.S. GAAP	Canadian GAAP	U.S. GAAP	Canadian GAAP	U.S. GAAP
Current assets (c)	$ 779	$ 837	$ 852	$ 911	$ 1,128	$ 1,276
Property, plant and equipment, net (a) (d)	12,193	11,633	10,862	10,264	9,421	8,686
Other assets (b) (j)	266	269	232	236	84	89
	$ 13,238	$ 12,739	$ 11,946	$ 11,411	$ 10,633	$ 10,051
Current liabilities (b) (c) (j)	$ 1,594	$ 1,663	$ 1,456	$ 1,635	$ 1,215	$ 1,301
Long-term debt (b) (c)	1,776	2,099	1,439	1,761	1,964	2,406
Other long-term liabilities (d)	632	632	519	519	304	266
Future income taxes (a) (b) (c) (d) (f) (j)	2,758	2,555	2,621	2,372	2,014	1,772
Capital securities and accrued return (b)	278	–	298	–	364	–
Share capital (e) (g) (h)	3,506	3,740	3,457	3,737	3,406	3,640
Retained earnings	2,694	2,085	2,156	1,478	1,366	683
Accumulated other comprehensive income						
Cash flow hedges, net of tax (c)	–	(20)	–	(76)	–	(7)
Minimum pension liability, net of tax (j)	–	(15)	–	(15)	–	(10)
	$ 13,238	$ 12,739	$ 11,946	$ 11,411	$ 10,633	$ 10,051

Condensed Consolidated Statements of Retained Earnings and Accumulated Other Comprehensive Income

	2004		2003		2002	
	Canadian GAAP	U.S. GAAP	Canadian GAAP	U.S. GAAP	Canadian GAAP	U.S. GAAP
Retained earnings, beginning of year	$ 2,156	$ 1,478	$ 1,366	$ 683	$ 722	$ 23
Net earnings	1,006	1,031	1,334	1,375	814	811
Dividends on common shares	(424)	(424)	(580)	(580)	(151)	(151)
Return and foreign exchange on capital securities, net of tax (b)	–	–	36	–	(18)	–
Stock-based compensation – retroactive adoption (e)	(44)	–	–	–	–	–
Asset retirement obligations – retroactive adoption (d)	–	–	–	–	(1)	–
Retained earnings, end of year	$ 2,694	$ 2,085	$ 2,156	$ 1,478	$ 1,366	$ 683
Accumulated other comprehensive income, beginning of year	$ –	$ (91)	$ –	$ (17)	$ –	$ 3
Cash flow hedges, net of tax (c)	–	56	–	(69)	–	(10)
Minimum pension liability, net of tax (j)	–	–	–	(5)	–	(10)
Accumulated other comprehensive income, end of year	$ –	$ (35)	$ –	$ (91)	$ –	$ (17)

Condensed Consolidated Statements of Earnings and Comprehensive Income

	2004		2003		2002	
	Canadian GAAP	U.S. GAAP	Canadian GAAP	U.S. GAAP	Canadian GAAP	U.S. GAAP
Sales and operating revenues (c) (i)	$ 8,440	$ 7,038	$ 7,658	$ 6,823	$ 6,384	$ 5,635
Costs and expenses (b) (c) (e) (i)	5,790	4,366	4,732	3,892	4,117	3,345
Accretion expense (d)	27	27	22	22	17	–
Depletion, depreciation and amortization (a) (d)	1,179	1,142	1,021	941	908	851
Interest – net (b)	33	60	73	102	104	136
Earnings before income taxes	1,411	1,443	1,810	1,866	1,238	1,303
Income taxes (a) (b) (c) (d) (f)	405	412	476	500	424	492
Earnings before cumulative effect of change in accounting principle	1,006	1,031	1,334	1,366	814	811
Cumulative effect of change in accounting principle, net of tax (d)	–	–	–	9	–	–
Net earnings	1,006	1,031	1,334	1,375	814	811
Other comprehensive income (c) (j)	–	(56)	–	74	–	20
Comprehensive income	$ 1,006	$ 975	$ 1,334	$ 1,449	$ 814	$ 831

Condensed Consolidated Statements of Cash Flows

	2004	2003	2002
Cash flow – operating activities – Canadian GAAP	$ 2,352	$ 2,538	$ 1,882
Adjustments:			
Return on capital securities payment	(26)	(29)	(31)
Settlement of asset retirement liabilities	–	–	16
Cash flow – operating activities – U.S. GAAP	2,326	2,509	1,867
Cash flow – financing activities – Canadian GAAP	149	(800)	3
Adjustments:			
Return on capital securities payment	26	29	31
Cash flow – financing activities – U.S. GAAP	175	(771)	34
Cash flow – investing activities – Canadian GAAP	(2,497)	(2,041)	(1,579)
Adjustments:			
Settlement of asset retirement liabilities	–	–	(16)
Cash flow – investing activities – U.S. GAAP	(2,497)	(2,041)	(1,595)
Change in cash and cash equivalents	$ 4	$ (303)	$ 306

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (CONTINUED)

The increases or decreases noted above refer to the following differences between U.S. GAAP and Canadian GAAP:

(a) Under Canadian GAAP the ceiling test has been modified by Accounting Guideline 16, "Oil and Gas Accounting – Full Cost" ("AcG-16"). Under AcG-16 the ceiling test is performed by comparing the carrying value of the cost centre based on the sum of the undiscounted cash flows from proved reserves using future prices and costs expected from the cost centre's use and eventual disposition. If the carrying value is unrecoverable the cost centre is written down to its fair value using the expected present value approach of proved plus probable reserves using future prices. Previously, the Company performed the cost recovery ceiling test for each cost centre which limited net capitalized costs to the undiscounted estimated future net revenue from proved reserves plus the cost of unproved properties and major development projects less impairment, using year-end prices or average prices in that year if appropriate. In addition, the aggregate value of all cost centres was previously further limited by including financing costs, administration expenses, future removal and site restoration costs and income taxes. Under U.S. GAAP, companies using the full cost method of accounting for oil and gas producing activities perform a ceiling test on each cost centre using discounted estimated future net revenue from proved reserves using a discount factor of 10 percent. Prices used in the U.S. GAAP ceiling tests performed for this reconciliation were those in effect at the applicable year-end. Financing and administration costs are excluded from the calculation under U.S. GAAP. At December 31, 2001, the Company recognized a U.S. GAAP ceiling test write down of $334 million after tax. Depletion expense for U.S. GAAP is reduced by $76 million (2003 – $80 million; 2002 – $88 million), net of tax of $27 million (2003 – $30 million; 2002 – $37 million).

    Under U.S. GAAP, prices used in determining proved reserves are those in effect at the applicable year-end. For Canadian GAAP, commencing in 2004, future prices and costs are used in determining proved reserves. The different prices result in lower proved reserves for U.S. GAAP. Additional depletion of $39 million, net of taxes of $14 million has been recorded under U.S. GAAP in 2004.

(b) The Company records the capital securities as a component of equity and the return and foreign exchange gains or losses thereon as a charge to retained earnings. Under U.S. GAAP, the capital securities, the accrued return thereon and costs of issue would be classified outside of shareholders' equity and the related return and foreign exchange gains or losses would be charged to earnings. See note 15, Capital Securities.

(c) The Company records all derivative instruments as assets and liabilities on the balance sheet based on their fair values as required under FAS 133, "Accounting for Derivative Instruments and Hedging Activities". At December 31, 2004, the Company recorded additional assets and liabilities for U.S. GAAP purposes of $52 million (2003 – $52 million; 2002 – $111 million) and $93 million (2003 – $172 million; 2002 – $122 million), respectively, for the fair values of derivative financial instruments. The Company also recorded a loss of less than $1 million, net of tax (2003 – loss of $2 million; 2002 – gain of $1 million), in revenue for U.S. GAAP purposes with respect to derivatives designated as fair value hedges relating to commodity price risk. In addition, the amount included in other comprehensive income was reduced by $51 million net of tax (2003 – increased by $69 million; 2002 – reduced by $10 million), for changes in the fair values of the derivatives designated as hedges of cash flows relating to commodity price risk and foreign exchange risk and the transfer to income of amounts applicable to cash flows occurring in 2004. On November 10, 2004, the Company unwound its long-dated foreign exchange forwards. The unrealized gain of $5 million, net of tax continues to be deferred in other comprehensive income and will be recognized at the dates that the underlying transactions are to take place. In prior years, the gains net of tax (2003 – $1 million; 2002 – $11 million) on foreign currency derivatives and natural gas basis swaps that did not qualify for hedge accounting under FAS 133 were included in income for U.S. GAAP purposes.

    Under U.S. GAAP, energy trading contracts entered into and physical energy trading inventories purchased on or before October 26, 2002 were recorded at fair value. These contracts include derivatives as well as energy trading contracts that do not meet the definition of derivatives. Effective October 26, 2002, inventories and the associated natural gas purchase

and sale contracts entered into after the effective date are no longer recorded at fair value in accordance with Emerging Issues Task Force 02-03, "Issues Involved in Accounting for Derivative Contracts held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities". Under Canadian GAAP, the impact of energy trading contracts is recorded as they settle. Under U.S. GAAP, at December 31, 2004 the Company recorded additional assets and liabilities of \$4 million (2003 – \$7 million; 2002 – \$37 million) and \$3 million (2003 – \$5 million; 2002 – \$19 million), respectively, and included the resulting unrealized loss, net of tax of \$1 million (2003 – loss of \$9 million; 2002 – loss of \$1 million) in earnings for the year. Under U.S. GAAP, gains and losses on energy trading contracts have been netted against sales and operating revenues.

(d) In 2003, the Company adopted FAS 143, "Accounting for Asset Retirement Obligations", which requires the fair value of a liability for an asset retirement obligation to be recorded in the period in which it is incurred and a corresponding increase in the carrying amount of the related tangible long-lived asset. The standard applies to legal obligations associated with the retirement of long-lived assets that result from the acquisition, construction, development and normal use of the asset. The liability is accreted at the end of each period through charges to accretion expense. The change was effective January 1, 2003, and the related cumulative effect of change in accounting principle to net earnings to December 31, 2002 was an increase of \$20 million, net of tax of \$11 million or \$0.02 per share (diluted). Effective January 1, 2004, under Canadian GAAP the Company adopted CICA section 3110, "Asset Retirement Obligations", which is substantially the same as the recommendations in FAS 143. CICA section 3110 was adopted retroactively with restatement. The application of asset retirement obligations did not have a material impact on the Company's depletion, depreciation and amortization rate. There was no impact on the Company's cash flow as a result of adopting asset retirement obligations.

The following table shows the effect on the Company's net earnings and earnings per share as if FAS 143 had been in effect in prior years. There would have been a \$10 million increase to net earnings for the year ended December 31, 2002.

As at and for the year ended December 31, 2002	
As reported	
Net earnings under U.S. GAAP	$ 811
Earnings per share under U.S. GAAP	
Basic	$ 1.94
Diluted	$ 1.93
Pro forma	
Net earnings under U.S. GAAP	$ 821
Earnings per share under U.S. GAAP	
Basic	$ 1.97
Diluted	$ 1.96
Asset retirement obligations	
Beginning of year	$ 269
End of year	$ 286

(e) On September 3, 2003, the Company modified the exercise price of all outstanding options. Under U.S. GAAP these options are required to be accounted for using variable accounting where the in-the-money portion of the vested stock options outstanding is adjusted through the statement of earnings as compensation expense over the remaining vesting period. The amount of stock-based compensation expense charged to earnings for the year ended December 31, 2003 was \$46 million. The compensation expense is revalued at each reporting date based on the share price and the number of vested stock options outstanding. In 2003, under Canadian GAAP no compensation expense was recorded for modified options.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (CONTINUED)

Effective January 1, 2004, under Canadian GAAP, the Company adopted CICA section 3870, "Stock-based Compensation and Other Stock-based Payments", retroactively without restatement of prior periods, which requires the Company to record a compensation expense over the vesting period of the options based on the fair value of the options granted. CICA section 3870 is consistent with the recommendations in FAS 123, "Accounting for Stock-based Compensation".

(f) The liability method under Canadian GAAP requires the measurement of future income tax liabilities and assets using income tax rates that reflect substantively enacted income tax rate reductions provided it is more likely than not that the Company will be eligible for such rate reductions in the period of reversal. U.S. GAAP allows recording of such rate reductions only when enacted.

(g) As a result of the reorganization of the capital structure which occurred in 2000, the deficit of Husky Oil Limited of $160 million was eliminated. Elimination of the deficit would not be permitted under U.S. GAAP.

(h) The Company recorded interest waived on subordinated shareholders' loans and dividends waived on Class C shares as a reduction of ownership charges. Under U.S. GAAP, waived interest and dividends in those years would be recorded as interest on subordinated shareholders' loans and dividends on Class C shares and as capital contributions.

(i) Under U.S. GAAP, transportation costs are included in cost of sales. Effective January 1, 2004, for Canadian purposes, certain transportation costs that were previously netted against revenue are now being recorded as cost of sales on a prospective basis. Transportation costs for 2003 and 2002 were $112 million and $113 million, respectively.

(j) The Company amortizes the portion of the unrecognized gains or losses that exceed 10 percent of the greater of the projected benefit obligation or the market-related value of pension plan assets. The market-related value of pension plan assets is the fair value of the assets. Under U.S. GAAP, an additional minimum liability is recognized if the unfunded accumulated benefit obligation exceeds the unfunded pension cost already recognized. If an additional minimum liability is recognized, an amount equal to the unrecognized prior service cost is recognized as an intangible asset and any excess is reported in other comprehensive income. At December 31, 2004, the additional minimum liability was decreased by $1 million (2003 – increase of $6 million; 2002 – increase of $19 million) with a decrease to other comprehensive income of less than $1 million (2003 – decrease of $5 million; 2002 – decrease of $10 million), net of tax.

Additional U.S. GAAP Disclosures

Corporate Acquisitions

As described in note 7, Corporate Acquisitions, the Company purchased all of the outstanding shares of Temple Exploration Inc. and Marathon Canada Limited. The Company also purchased the Western Canadian assets of Marathon International Petroleum Canada, Ltd. These transactions increased the reserve base and created cost efficiencies, increasing shareholder value.

Accounting for Derivative Instruments and Hedging Activities

Effective January 1, 2001, the Company adopted the provisions of FAS 133, which require that all derivatives be recognized as assets and liabilities on the balance sheet and measured at fair value. Gains or losses, including unrealized amounts, on derivatives that have not been designated as hedges are included in earnings as they arise.

For derivatives designated as fair value hedges, changes in the fair value are recognized in earnings together with equal or lesser amounts of changes in the fair value of the hedged item. No portion of the fair value of the derivatives related to time value has been excluded from the assessment of hedge effectiveness in these hedging relationships.

For derivatives designated as cash flow hedges, the portion of the changes in the fair value of the derivatives that are effective in hedging the changes in future cash flows are recognized in other comprehensive income until the hedged items are recognized in earnings. Any portion of the change in the fair value of the derivatives that is not effective in hedging the changes in future cash flows is included in earnings. No portion of the fair value of the derivatives related to time value has been excluded from the assessment of hedge effectiveness in these hedging relationships.

Stock Option Plan

FAS 123 establishes financial accounting and reporting standards for stock-based employee compensation plans as well as transactions in which an entity issues its equity instruments to acquire goods or services from non-employees. As permitted by FAS 123, Husky has elected to follow the intrinsic value method of accounting for stock-based compensation arrangements, as provided for in Accounting Principles Board ("APB") Opinion 25. Since all options were granted with exercise prices equal to the market price, no compensation expense has been charged to income at the time of the option grants. On September 3, 2003, the Company modified the exercise price of all outstanding options, resulting in the use of variable accounting for these modified stock options. The table below provides pro forma amounts prior to the application of variable accounting which required recognition of compensation expense on September 3, 2003. Effective January 1, 2004, the Company adopted CICA section 3870, which requires the Company to record a compensation expense over the vesting period of the options based on the fair value of the options granted. CICA section 3870 is consistent with the recommendations in FAS 123. Had compensation cost for Husky's stock options been determined based on the fair market value at the grant dates of the awards, and amortized on a straight-line basis over the vesting period, consistent with methodology prescribed by FAS 123, Husky's net earnings and earnings per share for the years ended December 31, 2003 and 2002 would have been the pro forma amounts indicated below:

	2003		*2002*	
	As Reported	*Pro Forma*	*As Reported*	*Pro Forma*
Net earnings under U.S. GAAP	$ 1,375	$ 1,407	$ 811	$ 798
Earnings per share – Basic	$ 3.28	$ 3.35	$ 1.94	$ 1.91
– Diluted	$ 3.26	$ 3.34	$ 1.93	$ 1.90

The fair values of all common share options granted were estimated on the date of grant using the Black-Scholes option-pricing model. The weighted average fair market value of options granted during the years 2003 and 2002 and the assumptions used in their determination are the same as described in note 16.

In December 2004, the Financial Accounting Standards Board ("FASB") issued FAS 123(R), "Share-based Payment", which replaces FAS 123 and supersedes APB Opinion 25. FAS 123(R) requires compensation cost related to share-based payments be recognized in the financial statements and that the cost must be measured based on the fair value of the equity or liability instruments issued. Under FAS 123(R) all share-based payment plans must be valued using option-pricing models. For U.S. GAAP, the liability related to the options issued under the Company's tandem plan will be measured at fair value using an option pricing model. Under Canadian GAAP, the liability will be measured based on the intrinsic value of the option. Over the life of the option the amount of compensation expense recognized will differ under U.S. and Canadian GAAP, creating a temporary GAAP timing difference. At exercise or surrender of the option, the compensation expense to be recorded will be equal to the cash payment which will be identical under U.S. and Canadian GAAP and there will no longer be a GAAP difference. FAS 123(R) is effective for the third quarter of 2005.

Depletion, Depreciation and Amortization

Upstream depletion, depreciation and amortization per gross equivalent barrel is calculated by converting natural gas volumes to a barrel of oil equivalent ("boe") using the ratio of 6 mcf of natural gas to 1 barrel of crude oil (sulphur volumes have been excluded from the calculation). Depletion, depreciation and amortization per boe as calculated under U.S. GAAP for the years ended December 31 were as follows:

	2004	*2003*	*2002*
Depletion, depreciation and amortization per boe	**$ 8.76**	$ 7.35	$ 6.96

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (CONTINUED)

Accounting for Variable Interest Entities

In January 2003, the FASB issued Financial Interpretation 46, "Accounting for Variable Interest Entities" ("FIN 46") that requires the consolidation of Variable Interest Entities ("VIEs"). VIEs are entities that have insufficient equity or their equity investors lack one or more of the specified elements that a controlling entity would have. The VIEs are controlled through financial interests that indicate control (referred to as "variable interests"). Variable interests are the rights or obligations that expose the holder of the variable interest to expected losses or expected residual gains of the entity. The holder of the majority of an entity's variable interests is considered the primary beneficiary of the VIE and is required to consolidate the VIE. In December 2003, the FASB issued FIN 46(R) which superseded FIN 46 and restricts the scope of the definition of entities that would be considered VIEs that require consolidation. The Company does not believe FIN 46(R) results in the consolidation of any additional entities.

SAB 106

In September 2004, the Securities and Exchange Commission issued Staff Accounting Bulletin 106 ("SAB 106") regarding the application of FAS 143 by oil and gas producing entities that follow the full cost accounting method. SAB 106 states that after the adoption of FAS 143 the future cash flows associated with the settlement of asset retirement obligations that have been accrued on the balance sheet should be excluded from the computation of the present value of estimated future net revenues for purposes of the full cost ceiling test calculation. The Company excludes the future cash outflows associated with settling asset retirement obligations from the present value of estimated future net cash flows and does not reduce the capitalized oil and gas costs by the asset retirement obligation accrued on the balance sheet. Costs subject to depletion and depreciation include estimated costs required to develop proved undeveloped reserves and the associated addition to the asset retirement obligations. The adoption of SAB 106 in the fourth quarter of 2004 did not have a material effect on the results of the ceiling test or depletion, depreciation and amortization calculations.

Accounting for Inventory Costs

In November 2004, the FASB issued FAS 151 which clarifies the accounting for abnormal amounts of idle facility expense, freight, handling costs and wasted material as they relate to inventory costing. FAS 151 requires these items to be recognized as current period expenses. Additionally, the allocation of fixed production overheads to the cost of inventory should be based on the normal capacity of the production facilities. FAS 151 is effective for inventory costs incurred during fiscal years beginning after June 15, 2005. The Company does not believe that the application of FAS 151 will have an impact on the financial statements.

Accounting for Exchanges of Nonmonetary Assets

In December 2004, the FASB issued FAS 153 which deals with the accounting for the exchanges of nonmonetary assets. FAS 153 is an amendment of APB Opinion 29. APB Opinion 29 requires that exchanges of nonmonetary assets should be measured based on the fair value of the assets exchanged. FAS 153 amends APB Opinion 29 to eliminate the exception from using fair market value for nonmonetary exchanges of similar productive assets and introduces a broader exception for exchanges of nonmonetary assets that do not have commercial substance. FAS 153 is effective for nonmonetary asset exchanges occurring in fiscal periods beginning after June 15, 2005. The Company does not believe that the application of FAS 153 will have an impact on the financial statements.

SUPPLEMENTAL FINANCIAL AND OPERATING INFORMATION

Quarterly Financial and Operating Information

Segmented Operational Information

		[illegible]				[illegible]			
		Q4	*Q3*	*Q2*	*Q1*	*Q4*	*Q3*	*Q2*	*Q1*
Upstream									
Daily production, before royalties									
Light crude oil & NGL *(mbbls/day)*		60.9	64.8	69.2	70.4	72.0	65.2	74.9	74.3
Medium crude oil *(mbbls/day)*		33.7	34.5	35.6	36.1	37.9	38.2	39.4	41.4
Heavy crude oil *(mbbls/day)*		113.8	108.8	107.4	105.6	107.8	99.2	94.7	97.8
		208.4	208.1	212.2	212.1	217.7	202.6	209.0	213.5
Natural gas *(mmcf/day)*		697.4	700.4	685.4	673.6	655.7	585.7	609.4	591.2
Total production *(mboe/day)*		324.6	324.8	326.4	324.4	327.0	300.2	310.6	312.1
Average sales prices									
Light crude oil & NGL *($/bbl)*		$ 51.48	$ 53.54	$ 47.41	$ 41.84	$ 37.59	$ 34.15	$ 35.58	$ 47.11
Medium crude oil *($/bbl)*		$ 35.06	$ 40.59	$ 35.98	$ 32.97	$ 27.25	$ 29.68	$ 30.48	$ 37.86
Heavy crude oil *($/bbl)*		$ 25.81	$ 34.92	$ 27.54	$ 26.38	$ 20.84	$ 25.13	$ 25.13	$ 33.02
Natural gas *($/mcf)*		$ 6.64	$ 5.92	$ 6.38	$ 6.05	$ 4.87	$ 5.40	$ 5.50	$ 7.80
Operating costs *($/boe)*		$ 7.50	$ 7.57	$ 7.17	$ 7.03	$ 6.87	$ 6.71	$ 6.80	$ 7.39
Operating netbacks (1)									
Light crude oil *($/boe)*		$ 36.47	$ 39.71	$ 35.33	$ 30.91	$ 26.76	$ 29.86	$ 28.24	$ 35.71
Medium crude oil *($/boe)*		$ 20.08	$ 22.32	$ 20.03	$ 17.80	$ 13.35	$ 15.63	$ 15.83	$ 21.91
Heavy crude oil *($/boe)*		$ 13.75	$ 20.76	$ 15.28	$ 14.35	$ 10.45	$ 14.00	$ 13.51	$ 19.03
Natural gas *($/mcfge)*		$ 4.29	$ 3.58	$ 3.98	$ 3.87	$ 3.14	$ 3.41	$ 3.28	$ 5.19
Total *($/boe)*		$ 22.85	$ 24.92	$ 23.05	$ 21.40	$ 16.97	$ 19.63	$ 19.28	$ 27.10
Net wells drilled (2)									
Exploration	Oil	23	4	5	7	3	4	1	3
	Gas	46	23	11	100	32	11	11	70
	Dry	3	1	1	28	1	–	3	17
		72	28	17	135	36	15	15	90
Development	Oil	131	188	85	95	116	202	65	107
	Gas	148	204	113	275	137	107	64	210
	Dry	5	14	10	24	5	14	6	32
		284	406	208	394	258	323	135	349
		356	434	225	529	294	338	150	439
Success ratio *(percent)*		98	97	95	90	98	96	94	89
Midstream									
Synthetic crude oil sales *(mbbls/day)*		52.5	60.1	44.1	58.2	62.2	66.0	66.5	59.4
Upgrading differential *($/bbl)*		$ 25.72	$ 15.26	$ 17.10	$ 13.80	$ 13.40	$ 11.91	$ 12.65	$ 14.11
Pipeline throughput *(mbbls/day)*		479	461	520	510	502	477	480	478
Refined Products									
Refined products sales volumes									
Light oil products *(million litres/day)*		8.1	8.8	8.5	8.4	8.2	8.5	7.8	8.3
Asphalt products *(mbbls/day)*		20.8	27.6	24.2	18.4	19.7	30.5	20.7	17.1
Refinery throughput									
Lloydminster refinery *(mbbls/day)*		26.1	23.8	26.7	24.8	26.1	26.6	25.4	24.8
Prince George refinery *(mbbls/day)*		8.6	9.2	10.4	10.9	11.5	8.2	11.0	10.6
Refinery utilization *(percent)*		99	94	106	102	107	99	104	101

(1) Operating netbacks are Husky's average prices less royalties and operating costs on a per unit basis.

(2) Western Canada.

Segmented Financial Information

	Upstream				Midstream			
					Upgrading			
($ millions)	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
2004								
Sales and operating revenues, net of royalties	$ 722	$ 817	$ 800	$ 781	$ 291	$ 308	$ 213	$ 246
Costs and expenses								
Operating, cost of sales, selling and general	247	255	240	225	222	268	182	212
Depletion, depreciation and amortization	283	278	262	254	5	5	4	5
Interest – net	–	–	–	–	–	–	–	–
Foreign exchange	–	–	–	–	–	–	–	–
	530	533	502	479	227	273	186	217
Earnings (loss) before income taxes	192	284	298	302	64	35	27	29
Current income taxes	89	59	29	34	–	–	–	–
Future income taxes	(9)	64	65	32	18	11	8	6
Net earnings (loss)	$ 112	$ 161	$ 204	$ 236	$ 46	$ 24	$ 19	$ 23
Capital employed	$ 7,747	$ 7,357	$ 7,215	$ 6,979	$ 480	$ 487	$ 484	$ 455
Capital expenditures (2)	$ 664	$ 509	$ 421	$ 563	$ 24	$ 12	$ 18	$ 8
Total assets (3)	$11,172	$10,666	$10,464	$10,302	$ 708	$ 698	$ 688	$ 653
2003 (4)								
Sales and operating revenues, net of royalties	$ 722	$ 740	$ 760	$ 964	$ 229	$ 252	$ 256	$ 276
Costs and expenses								
Operating, cost of sales, selling and general	227	203	216	227	196	225	228	252
Depletion, depreciation and amortization	263	218	214	223	5	5	5	5
Interest – net	–	–	–	–	–	–	–	–
Foreign exchange	–	–	–	–	–	–	–	–
	490	421	430	450	201	230	233	257
Earnings (loss) before income taxes	232	319	330	514	28	22	23	19
Current income taxes	5	13	39	38	1	–	–	–
Future income taxes	58	91	(83)	167	9	7	(3)	7
Net earnings (loss)	$ 169	$ 215	$ 374	$ 309	$ 18	$ 15	$ 26	$ 12
Capital employed	$ 6,709	$ 6,271	$ 6,187	$ 6,251	$ 456	$ 462	$ 468	$ 309
Capital expenditures (2)	$ 571	$ 443	$ 271	$ 493	$ 10	$ 5	$ 6	$ 4
Total assets (3)	$ 9,949	$ 8,882	$ 8,590	$ 8,700	$ 650	$ 655	$ 656	$ 663

(1) Eliminations relate to sales and operating revenues between segments recorded at transfer prices based on current market prices, and to unrealized intersegment profits in inventories.

(2) Excludes capitalized costs related to asset retirement obligations incurred during the period and corporate acquisitions.

(3) Includes goodwill on corporate acquisitions related to Upstream.

(4) Amounts as restated. Refer to note 3 to the Consolidated Financial Statements.

Midstream				Refined Products				Corporate and Eliminations [1]				Total			
Infrastructure and Marketing															
Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
$1,455	$1,564	$1,669	$1,438	$ 465	$ 515	$ 457	$ 360	$ (915)	$(1,013)	$ (929)	$ (804)	$ 2,018	$ 2,191	$ 2,210	$ 2,021
1,404	1,518	1,614	1,378	458	479	414	343	(890)	(988)	(886)	(779)	1,441	1,532	1,564	1,379
5	6	5	5	11	9	9	9	(2)	8	8	10	302	306	288	283
–	–	–	–	–	–	–	–	6	7	10	10	6	7	10	10
–	–	–	–	–	–	–	–	(46)	(66)	5	8	(46)	(66)	5	8
1,409	1,524	1,619	1,383	469	488	423	352	(932)	(1,039)	(863)	(751)	1,703	1,779	1,867	1,680
46	40	50	55	(4)	27	34	8	17	26	(66)	(53)	315	412	343	341
–	5	14	12	–	4	5	2	13	13	11	12	102	81	59	60
15	9	2	6	(1)	5	8	1	(28)	(44)	(38)	(27)	(5)	45	45	18
$ 31	$ 26	$ 34	$ 37	$ (3)	$ 18	$ 21	$ 5	$ 32	$ 57	$ (39)	$ (38)	$ 218	$ 286	$ 239	$ 263
$ 255	$ 282	$ 256	$ 237	$ 354	$ 372	$ 356	$ 297	$ (477)	$ (101)	$ (70)	$ (103)	$ 8,359	$ 8,397	$ 8,241	$ 7,865
$ 19	$ 5	$ 4	$ 3	$ 53	$ 29	$ 14	$ 10	$ 4	$ 8	$ 6	$ 5	$ 764	$ 563	$ 463	$ 589
$ 599	$ 610	$ 578	$ 660	$ 625	$ 647	$ 617	$ 578	$ 134	$ 278	$ 192	$ 121	$13,238	$12,899	$12,539	$12,314
$1,139	$1,170	$1,205	$1,432	$ 335	$ 431	$ 352	$ 384	$ (625)	$ (722)	$ (804)	$ (838)	$ 1,800	$ 1,871	$ 1,769	$ 2,218
1,089	1,125	1,166	1,367	319	391	341	375	(625)	(729)	(794)	(830)	1,206	1,215	1,157	1,391
6	5	5	5	6	6	7	7	13	9	8	6	293	243	239	246
–	–	–	–	–	–	–	–	16	16	20	21	16	16	20	21
–	–	–	–	–	–	–	–	(43)	–	(72)	(100)	(43)	–	(72)	(100)
1,095	1,130	1,171	1,372	325	397	348	382	(639)	(704)	(838)	(903)	1,472	1,474	1,344	1,558
44	40	34	60	10	34	4	2	14	(18)	34	65	328	397	425	660
22	4	(4)	5	(13)	14	3	5	7	4	4	–	22	35	42	48
(6)	10	15	18	17	(2)	(2)	(4)	(8)	7	15	16	70	113	(58)	204
$ 28	$ 26	$ 23	$ 37	$ 6	$ 22	$ 3	$ 1	$ 15	$ (29)	$ 15	$ 49	$ 236	$ 249	$ 441	$ 408
$ 348	$ 444	$ 440	$ 392	$ 315	$ 383	$ 405	$ 293	$ (148)	$ 110	$ 395	$ 373	$ 7,680	$ 7,670	$ 7,895	$ 7,618
$ 7	$ 5	$ 4	$ 2	$ 30	$ 11	$ 9	$ 8	$ 9	$ 5	$ 7	$ 2	$ 627	$ 469	$ 297	$ 509
$ 702	$ 793	$ 946	$ 848	$ 540	$ 588	$ 610	$ 612	$ 105	$ 850	$ 584	$ 407	$11,946	$11,768	$11,386	$11,230

Segmented Financial Information

($ millions)	[illegible]				[illegible]			
	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Capital expenditures (1)								
Upstream								
Western Canada	$ 433	$ 351	$ 270	$ 479	$ 372	$ 265	$ 179	$ 379
East Coast Canada and Frontier	167	152	138	82	194	169	90	104
International	64	6	13	2	5	9	2	10
	664	509	421	563	571	443	271	493
Midstream								
Upgrader	24	12	18	8	10	5	6	4
Infrastructure and marketing	19	5	4	3	7	5	4	2
	43	17	22	11	17	10	10	6
Refined Products	53	29	14	10	30	11	9	8
Corporate	4	8	6	5	9	5	7	2
	$ 764	$ 563	$ 463	$ 589	$ 627	$ 469	$ 297	$ 509

(1) Excludes capitalized costs related to asset retirement obligations incurred during the period and corporate acquisitions.

Five-year Financial and Operating Information

Segmented Financial Information

	Upstream					*Midstream*									
						Upgrading					*Infrastructure and Marketing*				
($ millions)	*2004*	*2003*	*2002*	*2001*	*2000*	*2004*	*2003*	*2002*	*2001*	*2000*	*2004*	*2003*	*2002*	*2001*	*2000*
Year ended December 31 (2)															
Sales and operating revenues, net of royalties	**$ 3,120**	$ 3,186	$ 2,665	$ 2,165	$ 1,549	**$ 1,058**	$ 1,013	$ 909	$ 886	$ 1,006	**$ 6,126**	$ 4,946	$ 4,230	$ 4,380	$ 2,309
Costs and expenses															
Operating, cost of sales, selling and general	**967**	873	743	662	388	**884**	901	811	638	848	**5,914**	4,747	4,038	4,193	2,193
Depletion, depreciation and amortization	**1,077**	918	822	702	402	**19**	20	18	17	16	**21**	21	20	17	15
Interest – net	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Foreign exchange	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
	2,044	1,791	1,565	1,364	790	**903**	921	829	655	864	**5,935**	4,768	4,058	4,210	2,208
Earnings (loss) before income taxes	**1,076**	1,395	1,100	801	759	**155**	92	80	231	142	**191**	178	172	170	101
Current income taxes	**211**	95	55	17	10	**–**	1	1	1	1	**31**	27	6	1	–
Future income taxes	**152**	233	346	293	308	**43**	20	25	72	53	**32**	37	59	71	45
Net earnings (loss)	**$ 713**	$ 1,067	$ 699	$ 491	$ 441	**$ 112**	$ 71	$ 54	$ 158	$ 88	**$ 128**	$ 114	$ 107	$ 98	$ 56
Capital employed – As at December 31	**$ 7,747**	$ 6,709	$ 6,100	$ 5,763	$ 5,434	**$ 480**	$ 456	$ 319	$ 320	$ 352	**$ 255**	$ 348	$ 429	$ 393	$ 310
Total assets – As at December 31 (3)	**$11,172**	$ 9,949	$ 8,272	$ 7,443	$ 6,777	**$ 708**	$ 650	$ 659	$ 645	$ 614	**$ 599**	$ 702	$ 851	$ 863	$ 1,001

(1) Eliminations relate to sales and operating revenues between segments recorded at transfer prices based on current market prices, and to unrealized intersegment profits in inventories.

(2) 2003 and prior years' amounts as restated. Refer to note 3 to the Consolidated Financial Statements.

(3) Includes goodwill on corporate acquisitions related to Upstream.

Segmented Financial Information

[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	2000
Capital expenditures (1)					
Upstream					
Western Canada	$ 1,533	$ 1,195	$ 1,043	$ 1,023	$ 419
East Coast Canada and Frontier	539	557	458	191	194
International	85	26	75	104	87
	2,157	1,778	1,576	1,318	700
Midstream					
Upgrader	62	25	41	47	12
Infrastructure and marketing	31	18	23	58	47
	93	43	64	105	59
Refined Products	106	58	44	29	29
Corporate	23	23	23	22	15
	$ 2,379	$ 1,902	$ 1,707	$ 1,474	$ 803

(1) Excludes capitalized costs related to asset retirement obligations incurred during the period and corporate acquisitions.

Segmented Financial Information (continued)

	Refined Products					*Corporate and Eliminations* (1)					*Total*				
($ millions)	*2004*	*2003*	*2002*	*2001*	*2000*	*2004*	*2003*	*2002*	*2001*	*2000*	*2004*	*2003*	*2002*	*2001*	*2000*
Year ended December 31 (2)															
Sales and operating revenues, net of royalties	$ 1,797	$ 1,502	$ 1,310	$ 1,349	$ 1,347	$ (3,661)	$ (2,989)	$ (2,730)	$ (2,184)	$ (1,145)	$ 8,440	$ 7,658	$ 6,384	$ 6,596	$ 5,066
Costs and expenses															
Operating, cost of sales, selling and general	1,694	1,426	1,224	1,208	1,290	(3,543)	(2,978)	(2,695)	(2,165)	(1,060)	5,916	4,969	4,121	4,536	3,659
Depletion, depreciation and amortization	38	26	31	27	27	24	36	17	15	16	1,179	1,021	908	778	476
Interest – net	–	–	–	–	–	33	73	104	101	101	33	73	104	101	101
Foreign exchange	–	–	–	–	–	(99)	(215)	13	94	39	(99)	(215)	13	94	39
	1,732	1,452	1,255	1,235	1,317	(3,585)	(3,084)	(2,561)	(1,955)	(904)	7,029	5,848	5,146	5,509	4,275
Earnings (loss) before income taxes	65	50	55	114	30	(76)	95	(169)	(229)	(241)	1,411	1,810	1,238	1,087	791
Current income taxes	11	9	4	1	1	49	15	–	–	–	302	147	66	20	12
Future income taxes	13	9	18	48	14	(137)	30	(90)	(81)	(66)	103	329	358	403	354
Net earnings (loss)	$ 41	$ 32	$ 33	$ 65	$ 15	$ 12	$ 50	$ (79)	$ (148)	$ (175)	$ 1,006	$ 1,334	$ 814	$ 664	$ 425
Capital employed – As at December 31	$ 354	$ 315	$ 316	$ 307	$ 330	$ (477)	$ (148)	$ 357	$ (106)	$ (74)	$ 8,359	$ 7,680	$ 7,521	$ 6,677	$ 6,352
Total assets – As at December 31	$ 625	$ 540	$ 537	$ 431	$ 490	$ 134	$ 105	$ 314	$ 30	$ (5)	$ 13,238	$11,946	$10,633	$ 9,412	$ 8,877

Upstream Operating Information

	2004	2003	2002	2001	2000
Daily production, before royalties					
Light crude oil & NGL *(mbbls/day)*	**66.2**	71.6	65.4	46.4	42.8
Medium crude oil *(mbbls/day)*	**35.0**	39.2	44.8	47.2	20.8
Heavy crude oil *(mbbls/day)*	**108.9**	99.9	95.1	83.8	53.5
	210.1	210.7	205.3	177.4	117.1
Natural gas *(mmcf/day)*	**689.2**	610.6	569.2	572.6	358.0
Total production *(mboe/day)*	**325.0**	312.5	300.2	272.8	176.8
Average sales prices					
Light crude oil & NGL *($/bbl)*	**$ 48.34**	$ 39.53	$ 36.17	$ 33.15	$ 38.95
Medium crude oil *($/bbl)*	**$ 36.13**	$ 31.42	$ 30.16	$ 23.69	$ 29.56
Heavy crude oil *($/bbl)*	**$ 28.66**	$ 25.87	$ 26.60	$ 17.02	$ 26.45
Natural gas *($/mcf)*	**$ 6.25**	$ 5.86	$ 3.83	$ 5.47	$ 5.18
Operating costs *($/boe)*	**$ 7.32**	$ 6.92	$ 6.24	$ 6.08	$ 5.27
Operating netbacks (1)					
Light crude oil *($/boe)*	**$ 35.42**	$ 30.21	$ 25.64	$ 20.37	$ 23.24
Medium crude oil *($/boe)*	**$ 20.03**	$ 16.76	$ 17.14	$ 12.29	$ 19.99
Heavy crude oil *($/boe)*	**$ 16.02**	$ 14.13	$ 15.85	$ 7.87	$ 17.29
Natural gas *($/mcfge)*	**$ 3.92**	$ 3.71	$ 2.46	$ 3.51	$ 3.61

(1) Operating netbacks are Husky's average prices less royalties and operating costs on a per unit basis.

Upstream Operating Information

		2004		2003		2002		2001		2000	
		Gross	*Net*	*Gross*	*Net*	*Gross*	*Net*	*Gross*	*Net*	*Gross*	*Net*
Wells drilled (1)(2)											
Exploration	Oil	**45**	**39**	12	11	21	20	78	76	16	13
	Gas	**234**	**180**	147	124	139	131	102	90	30	20
	Dry	**34**	**33**	22	21	15	14	36	34	9	9
		313	**252**	181	156	175	165	216	200	55	42
Development	Oil	**552**	**499**	520	490	497	453	594	542	411	363
	Gas	**807**	**740**	540	518	485	453	251	221	92	70
	Dry	**57**	**53**	60	57	58	55	68	63	30	28
		1,416	**1,292**	1,120	1,065	1,040	961	913	826	533	461
		1,729	**1,544**	1,301	1,221	1,215	1,126	1,129	1,026	588	503
Success ratio *(percent)*		**95**	**94**	94	94	94	94	91	91	93	93

(1) Western Canada.
(2) Includes non-operated wells.

Selected Ten-year Financial and Operating Summary

($ millions, except where indicated)	2004	2003	2002	2001	2000	1999	1998	1997	1996	1995
Financial Highlights (1)										
Sales and operating revenues, net of royalties	**$ 8,440**	$ 7,658	$ 6,384	$ 6,596	$ 5,066	$ 2,787	$ 2,023	$ 2,282	$ 2,104	$ 1,783
Net earnings (loss)	**$ 1,006**	$ 1,334	$ 814	$ 664	$ 425	$ 95	$ (1)	$ 55	$ 50	$ 21
Earnings per share										
Basic	**$ 2.37**	$ 3.26	$ 1.91	$ 1.51	$ 1.24	$ 0.34	$ (0.03)	$ 0.20	$ 0.18	$ 0.08
Diluted	**$ 2.36**	$ 3.25	$ 1.90	$ 1.50	$ 1.24	$ 0.34	$ (0.03)	$ 0.20	$ 0.18	$ 0.08
Capital expenditures (2)	**$ 2,379**	$ 1,902	$ 1,707	$ 1,474	$ 803	$ 706	$ 829	$ 601	$ 218	$ 155
Total debt	**$ 1,881**	$ 1,769	$ 2,385	$ 2,192	$ 2,378	$ 1,382	$ 1,131	$ 1,014	$ 853	$ 1,474
Debt to capital employed *(percent)*	**23**	23	32	33	37	41	39	43	42	63
Reinvestment ratio (3) *(percent)*	**109**	90	76	78	57	134	199	132	46	44
Return on average capital employed (4) *(percent)*	**12.8**	18.1	12.3	11.1	12.1	6.9	4.3	7.2	6.7	5.5
Return on equity (5) *(percent)*	**16.2**	24.1	16.9	15.7	18.9	11.4	6.9	12.2	11.8	14.2
Upstream										
Daily production, before royalties										
Light crude oil & NGL *(mbbls/day)*	**66.2**	71.6	65.4	46.4	42.8	22.3	23.7	23.6	24.2	23.6
Medium crude oil *(mbbls/day)*	**35.0**	39.2	44.8	47.2	20.8	4.2	3.9	4.0	4.1	4.1
Heavy crude oil *(mbbls/day)*	**108.9**	99.9	95.1	83.8	53.5	42.1	42.0	41.9	34.5	30.0
	210.1	210.7	205.3	177.4	117.1	68.6	69.6	69.5	62.8	57.7
Natural gas *(mmcf/day)*	**689**	611	569	573	358	251	233	246	268	286
Total production *(mboe/day)*	**325.0**	312.5	300.2	272.8	176.8	110.4	108.4	110.6	107.5	105.4
Total proved reserves, before royalties *(mmboe)*	**791**	887	918	927	872	430	431	421	432	416
Midstream										
Synthetic crude oil sales *(mbbls/day)*	**53.7**	63.6	59.3	59.5	60.6	61.9	54.8	27.5	26.8	26.6
Upgrading differential *($/bbl)*	**$ 17.79**	$ 12.88	$ 10.81	$ 17.91	$ 13.77	$ 6.49	$ 7.85	$ 8.54	$ 5.94	$ 4.34
Pipeline throughput *(mbbls/day)*	**492**	484	457	537	528	394	412	417	359	296
Refined Products										
Light oil products sales *(million litres/day)*	**8.4**	8.2	7.7	7.6	7.4	7.6	6.0	4.5	4.2	3.9
Asphalt products sales *(mbbls/day)*	**22.8**	22.0	20.8	21.4	20.2	17.1	19.5	17.7	15.1	13.5
Refinery throughput										
Prince George refinery *(mbbls/day)*	**9.8**	10.3	10.1	10.2	9.2	10.2	9.9	10.3	10.0	9.9
Lloydminster refinery *(mbbls/day)*	**25.3**	25.7	22.0	23.7	23.4	17.9	21.9	21.5	18.4	15.6
Refinery utilization *(percent)*	**100**	103	92	97	93	80	91	91	81	73

(1) 2003 and prior years' amounts as restated. Refer to note 3 to the Consolidated Financial Statements.
(2) Excludes capitalized costs related to asset retirement obligations incurred during the period and corporate acquisitions.
(3) Reinvestment ratio is based on net capital expenditures including corporate acquisitions (other than Renaissance Energy Ltd.).
(4) Capital employed for purposes of this calculation has been weighted for 2000.
(5) Equity for purposes of this calculation has been weighted for 2000 and includes amounts due to shareholders prior to August 25, 2000.

CORPORATE INFORMATION

[illegible]

Victor T. K. Li, Co-Chairman, a resident of Hong Kong, has been a director of Husky Energy Inc. since 2000. Mr. Li is managing director and deputy chairman of Cheung Kong (Holdings) Limited. He is deputy chairman and executive director of Hutchison Whampoa Limited, chairman and director of Cheung Kong Infrastructure Holdings Limited, and of CK Life Sciences Int'l., (Holdings) Inc. Mr. Li is an executive director of Hongkong Electric Holdings Limited and a director of The Hongkong and Shanghai Banking Corporation Limited.

[illegible] a resident of Hong Kong, has been a director of Husky Energy Inc. since 2000. Mr. Fok is group managing director and executive director of Hutchison Whampoa Limited. He is chairman and director of Hutchison Harbour Ring Limited, Hutchison Telecommunications (Australia) Limited, Partner Communications Company Ltd., Hutchison Global Communications Limited (formerly Vanda Systems & Communications Holdings Limited), and Hutchison Telecommunications International Limited. Mr. Fok is the deputy chairman and a director of Cheung Kong Infrastructure Holdings Limited and Hongkong Electric Holdings Limited and a director of Cheung Kong (Holdings) Limited and Hutchison Whampoa Finance (CI) Limited.

(3) William Shurniak, Deputy Chairman, a resident of Australia, has been a director of Husky Energy Inc. since 2000. Mr. Shurniak is a director and chairman of ETSA Utilities, Powercor Australia Limited and CitiPower Pty Ltd. He is a director of Hutchison Whampoa Limited and Envestra Limited.

R. Donald Fullerton (1), Director, a resident of Toronto, has been a director of Husky Energy Inc. since 2003. Mr. Fullerton is a director of George Weston Limited, Asia Satellite Telecommunications Holdings Limited and Partner Communications Company Ltd.

(5) Martin J. G. Glynn (1), Director, a resident of New York, has been a director of Husky Energy Inc. since 2000. Mr. Glynn is the president, chief executive officer and a director of HSBC Bank USA.

(6) Terence C. Y. Hui (1), Director, a resident of Vancouver, has been a director of Husky Energy Inc. since 2000. Mr. Hui is a director, the president & chief executive officer of Concord Pacific Group Inc. He is a director and the president of Adex Securities Inc. and a director and chairman of Maximizer Software Inc. and a director of abc Multiactive Limited.

(7) Brent D. Kinney (3), Director, a resident of Dubai, United Arab Emirates, has been a director of Husky Energy Inc. since 2000. Mr. Kinney is an independent businessman and a director of Dragon Oil plc listed on the London, England, Stock Exchange.

(8) Holger Kluge (2) (3) (4), Director, a resident of Toronto, has been a director of Husky Energy Inc. since 2000. Mr. Kluge is a director of Hutchison Whampoa Limited, Hongkong Electric Holdings Limited, Hutchison Telecommunications (Australia) Limited, Loring Ward International Limited and TOM Group Limited.

(9) Poh Chan Koh, Director, a resident of Hong Kong, has been a director of Husky Energy Inc. since 2000. Miss Koh is the finance director of Harbour Plaza Hotel Management (International) Ltd.

(10) Eva L. Kwok (2) (4), Director, a resident of Vancouver, has been a director of Husky Energy Inc. since 2000. Mrs. Kwok is a director, chairman and chief executive officer of Amara International Investment Corp. She is a director of the Bank of Montreal Group of Companies, CK Life Sciences Int'l., (Holdings) Inc., Cheung Kong Infrastructure Holdings Limited and Shoppers Drug Mart.

(11) Stanley T. L. Kwok (3), Director, a resident of Vancouver, has been a director of Husky Energy Inc. since 2000. Mr. Kwok is the president of Stanley Kwok Consultants. He is a director and President of Amara International Investment Corp., and a director of Cheung Kong (Holdings) Limited.

(12) John C.S. Lau, President & CEO, Director, a resident of Calgary, has been a director of Husky Energy Inc. since 2000.

(13) Wayne E. Shaw (1) (4), Director, a resident of Toronto, has been a director of Husky Energy Inc. since 2000. Mr. Shaw is a senior partner at Stikeman Elliott LLP, Barristers & Solicitors.

(14) Frank J. Sixt (2), Director, a resident of Hong Kong, has been a director of Husky Energy Inc. since 2000. Mr. Sixt is group finance director and executive director of Hutchison Whampoa Limited. He is the chairman and a director of TOM Group Limited and TOM Online Inc., an executive director of Cheung Kong Infrastructure Holdings Limited and Hongkong Electric Holdings Limited, and a director of Cheung Kong (Holdings) Limited, Hutchison Whampoa Finance (CI) Limited, Hutchison Telecommunications (Australia) Limited, Partner Communications Company Ltd., Hutchison Telecommunications International Limited and Hutchison Global Communications Holdings Limited.

The Management Information Circular and the Annual Information Form contain additional information regarding the Directors.

(1) Audit Committee
(2) Compensation Committee
(3) Health, Safety & Environment Committee
(4) Corporate Governance Committee

Husky Energy Inc.

Husky Oil Operations Limited

in C. S. Lau, president and chief executive officer is responsible for Husky's corporate direction, strategic planning and corporate policies, and is also a member of the Company's Board of Directors. Before joining Husky he served in a number of senior executive roles within the Cheung Kong (Holdings) Limited and Hutchison Whampoa Limited group of companies. Mr. Lau is a fellow member of the Institute of Chartered Accountants, the Australian Society of Accountants, the Hong Kong Society of Accountants, the Taxation Institute of Hong Kong, and the Institute of Chartered Secretaries of Administrators of the United Kingdom.

es D. Girgulis was appointed vice president, legal and corporate secretary of Husky Energy in 2000. He was previously general counsel and corporate secretary of Husky Oil Limited. Prior to joining Husky he held positions with Alberta and Southern Gas Co. and Alberta Natural Gas Company. Mr. Girgulis was called to the Alberta Bar in 1982.

Donald R. Ingram, senior vice president, midstream & refined products has been an officer of Husky since 1994. He joined the Company in 1982 and has over 30 years in the midstream and downstream business. Mr. Ingram was formerly president and CEO of Husky's U.S. downstream subsidiary. He is a Certified Management Accountant (CMA) and is a fellow of the Society of Management Accountants of Canada (FCMA).

(4) Neil D. McGee was appointed vice president and chief financial officer of Husky Energy in 2000, after joining Husky in 1998. Prior to joining Husky, he served as senior manager of corporate finance and corporate secretary at Hutchison Whampoa.

(5) L. Geoffrey Barlow was appointed controller in 2000 and promoted to vice president and controller in 2003. He was previously controller and a member of the management team at Renaissance Energy Ltd. Mr. Barlow is a Chartered Accountant (CA) and is a member of the Institute of Chartered Accountants of Alberta and the Financial Executive Institute of Canada.

(6) Larry R. Bell was appointed vice president, exploration and production services in 2002, and is responsible for surface land, mineral land, drilling and completions, reservoir engineering and reserves. Mr. Bell previously held management and executive positions with Dome Petroleum, Amoco Canada, Crestar Energy and Gulf Canada. He is a member of the Association of Professional Engineers, Geologists and Geophysicists of Alberta, and director and chairman of Western Canada Spill Services Ltd.

(7) Wendell Carroll, vice president, corporate administration, joined Husky in 2000 and brings with him 30 years' experience as a senior manager with TransCanada PipeLines, Fracmaster and Bow Valley Industries. He is accountable for human resources, health, safety and environment, risk management, diversity, materials and services management, and facilities and records management and real estate.

(8) Robert S. Coward became a corporate officer in 1993 and has served with Husky since 1977. He was appointed vice president, Western Canada production in 2000 and is responsible for optimizing the value of Husky's assets by increasing both reserves and production, and by controlling costs. Mr. Coward is a member of the Association of Professional Engineers, Geologists and Geophysicists of Alberta.

(9) J. Michael D'Aguiar joined Husky as treasurer in 2002, and is responsible for the treasury department and associated financial functions. He has extensive financial experience in the international upstream oil industry. Prior to joining Husky he was chief financial officer of Ranger Oil.

(10) Walter DeBoni was appointed vice president, Canadian Frontier and International Business in 2002, and is responsible for Husky's East Coast and international operations. Before joining Husky he served as president & CEO of Bow Valley Energy, chairman of ARC Energy Trust and President & COO of Morrison Petroleums. Mr. DeBoni is a member of the Association of Professional Engineers, Geologists and Geophysicists of Alberta and the Society of Petroleum Engineers.

(11) David R. Taylor is vice president, exploration with responsibility for capitalizing on Husky's quality assets. Mr. Taylor was previously vice president of exploration for Renaissance Energy and held senior technical and executive positions at Chauvco Resources, Imperial Oil and Exxon. He is a member of the Association of Professional Engineers, Geologists and Geophysicists of Alberta, the Canadian Society of Petroleum Geologists and the American Association of Petroleum Geologists.

(12) Roy C. Warnock has more than 25 years' experience in oil refining and upgrading, and joined Husky in 1983. He served as the manager of Husky's Prince George refinery and the Lloydminster upgrader, before his appointment as vice president, upgrading and refining. Mr. Warnock is a member of the Association of Professional Engineers, Geologists and Geophysicists of Alberta, and Association of Professional Engineers and Geoscientists of Saskatchewan.

(13) Bill Watson was appointed vice president, engineering and project management in 2004, and brings more than 30 years of experience in the energy business to Husky. Previously Mr. Watson was vice president of Triton Equatorial Guinea Inc., a wholly owned subsidiary of Amerada Hess, and held many management and executive positions with Marathon Oil Company including President of Marathon Canada Ltd.

INVESTOR INFORMATION

Common Share Information

Year ended December 31 ($ millions)		**2004**	2003	2002
Share price	High	**$ 35.65**	$ 23.95	$ 17.98
	Low	**$ 22.73**	$ 16.03	$ 14.00
	Close at December 31	**$ 34.25**	$ 23.47	$ 16.47
Average daily trading volumes *(thousands)*		**482**	400	463
Number of common shares outstanding, December 31 *(thousands)*		**423,736**	422,176	417,874
Number of weighted average common shares outstanding *(thousands)*				
	Basic	**423,362**	419,543	417,425
	Diluted	**425,691**	421,549	419,334

Trading in the common shares of Husky Energy Inc. ("HSE") commenced on the Toronto Stock Exchange on August 28, 2000. The Company is represented in the S&P/TSX Composite, S&P/TSX Canadian Energy Sector and in the S&P/TSX 60 indices.

TORONTO STOCK EXCHANGE LISTING

HSE

OUTSTANDING SHARES

The number of common shares outstanding (in thousands) at December 31, 2004 was 423,736.

TRANSFER AGENT AND REGISTRAR

Husky's transfer agent and registrar is Computershare Trust Company of Canada. In the United States, the transfer agent and registrar is Computershare Trust Company, Inc. Share certificates may be transferred at Computershare's principal offices in Calgary, Toronto, Montreal and Vancouver, and at Computershare's principal office in Denver, Colorado, in the United States.

Queries regarding share certificates, dividends and estate transfers should be directed to Computershare Trust Company at 1-888-267-6555 (toll free in North America).

CORPORATE OFFICE

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Visit Husky Energy's website at www.huskyenergy.ca

Terra Nova website: www.terranovaproject.com

Wenchang website: www.huskywenchang.com

White Rose website: www.huskywhiterose.com

AUDITORS

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DIVIDENDS

Husky's Board of Directors has approved a dividend policy that pays quarterly dividends. This policy was reviewed by the Board in April 2004 and the quarterly dividend was increased from $0.10 to $0.12 ($0.48 annually) per common share. This policy will continue to be reviewed by the Board from time to time. Additionally, in November 2004 the Board of Directors approved a special cash dividend of $0.54 per common share, which was paid on January 1, 2005.

ANNUAL MEETING

The annual meeting of shareholders will be held at 10:30 a.m. on April 21, 2005 in the Crystal Ballroom at the Fairmont Palliser Hotel, 133 Ninth Avenue S.W., Calgary, Alberta.

ADDITIONAL PUBLICATIONS

The following publications are made available on our website or from our Investor Relations department:

- Annual Information Form, filed with Canadian securities regulators
- Form 40-F, filed with the U.S. Securities and Exchange Commission
- Quarterly Reports

Terms and Abbreviations

bbls	barrels
bps	basis points
mbbls	thousand barrels
mbbls/day	thousand barrels per day
mmbbls	million barrels
mcf	thousand cubic feet
mmcf	million cubic feet
mmcf/day	million cubic feet per day
bcf	billion cubic feet
tcf	trillion cubic feet
boe	barrels of oil equivalent
mboe	thousand barrels of oil equivalent
mboe/day	thousand barrels of oil equivalent per day
mmboe	million barrels of oil equivalent
mcfge	thousand cubic feet of gas equivalent

GJ	gigajoule
mmbtu	million British Thermal Units
mmlt	million long tons
MW	megawatt
MWh	megawatt hour
NGL	natural gas liquids
WTI	West Texas Intermediate
NYMEX	New York Mercantile Exchange
NIT	NOVA Inventory Transfer (1)
LIBOR	London Interbank Offered Rate
CDOR	Certificate of Deposit Offered Rate
hectare	1 hectare is equal to 2.47 acres

(1) NOVA Inventory Transfer is an exchange or transfer of title of gas that has been received into the NOVA pipeline system but not delivered to a connecting pipeline.

Capital Employed	Short- and long-term debt and shareholders' equity
Capital Expenditures	Includes capitalized administrative expenses and capitalized interest but does not include proceeds or other assets
Equity	Capital securities and accrued return, shares, retained earnings and amounts due to shareholders prior to August 25, 2000
Net Debt	Total debt net of cash and cash equivalents
Total Debt	Long-term debt including current portion and bank operating loans

Natural gas converted on the basis that six mcf of natural gas equals one barrel of oil.

In this report, the terms "Husky Energy Inc.," "Husky" or "the Company" mean Husky Energy Inc. and its subsidiaries and partnership interests on a consolidated basis.

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Printed on recycled paper. Printed in Canada.